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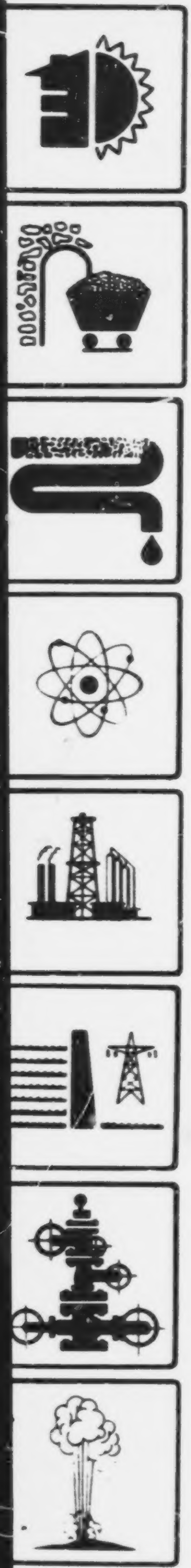

Technology Characterizations

Environmental Information Handbook

June 1981
Second Edition

U.S. DEPARTMENT OF ENERGY
Assistant Secretary, Environmental
Protection, Safety, and Emergency Preparedness
Office of Environmental Programs

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June 1981
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U.S. DEPARTMENT OF ENERGY
Assistant Secretary, Environmental
Protection, Safety, and Emergency Preparedness
Office of Environmental Programs
Washington, D.C. 20545

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FOREWORD

The Environmental Information Handbook Series was conceived and instituted in 1980 to promote the transfer of energy-related environmental information being used within the Department of Energy for policy and planning analyses to the non-Federal sectors. The series is meant to serve as a set of basic information reference documents for use by both the public and private sectors. The content is reliable and will assist decisionmaking and research on problems affecting energy and the environment.

This Handbook deals with environmental characterization information for a range of energy supply systems. Environmental residuals and physical resource requirements are the principal information provided. The numerical factors are useful for evaluating alternative policy and technical strategies and for assessing the environmental impact of facility siting and energy production. The positive user reception given to this Handbook underscores the fundamental importance of this kind of information to sound decisionmaking.

Considerable effort has been expended to provide the information in a useful and comprehensible format. The information base is subject to change and further enhancement as additional or improved information becomes available. User comments are welcomed to improve the quality of information presented and should be directed to Dario Monti, Director, Technology Assessments Division. Comments will be taken into account in the preparation of later editions.

The development and maintenance of the information is the responsibility of the Technology Assessments Division. This edition of the Handbook was prepared with the technical services of The Aerospace Corporation, Mueller Associates, Inc., and its subcontractor, Science Applications, Inc.

Peter W. House, Director
Office of Environmental Assessments
Office of Environmental Protection,
  Safety, and Emergency Preparedness

PREFACE

In the Preface to the first edition of this Handbook (DOE/EV-0072), the steps to be undertaken in developing the energy-related environmental information base were enunciated. Further work was to be directed at enhancing several important attributes of the information: its representative character, consistency, validity, and currentness. Particularly, the information summaries provided in the Handbook were to be augmented by a set of supplementary documents referred to as Environmental Information Characterization Reports (ECIRs), whose purpose is to present a more explicit treatment of the origin and derivation of the information.

In the ensuing year since publication of the first edition, effort has proceeded on three tracks: further screening of the information for correctness and consistency, reformatting of the information sheets to promote readability and a uniform presentation, and development of 15 ECIRs for a number of key energy technologies. This second edition presents the completed portion of that work, including ECIRs for the following systems: coal-fired power plants, eastern coal; coal-fired power plants, western coal; pressurized water reactor nuclear power plant; and oil shale, surface retorting (Paraho process). The ECIRs, including those under development, will ordinarily be published as separate volumes. The user should refer to the Appendix for the listing of ECIRs under development and scheduled for publication late in calendar year 1981.

The specific energy technologies included in the Handbook are divided into the following general areas: nuclear, petroleum, natural gas, synthetic fuels, coal, solar, geothermal, and hydroelectric. Each technology is characterized in terms of the resources required, costs, residuals released, energy products, and occupational safety and health data. The information is based on a facility of particular size and design, with the data presented on the basis of annual quantities or total facility lifetime quantities (e.g., construction materials), as appropriate. In addition, the data are normalized to 10^{12} (1 trillion) Btu energy output to facilitate cross-technology comparison and use of the data in computerized data bases.

Plans for extending work on the information base into fiscal 1982 depend on the availability of funds. The work will emphasize continued development of ECIRs for key technologies and the updating of this Handbook.

EXPLANATORY NOTES

For each energy system summarized in this Handbook, the tabular entries in the "Per 10^{12} Btu Energy Produced" column are expressed in English units. The corresponding annual quantities (used, released, and produced), also expressed in English units, are obtained by multiplying the "Per 10^{12} Btu Energy Produced" entry by the reference energy system's "Annual Energy Production," listed under FACILITY OPERATING PARAMETERS. For example, for the Open Pit Uranium Mine, 0.27 ton of particulates is released per 10^{12} Btu of energy produced. This translates to an annual emission level of 31 tons (28 tonnes) for the mine producing 115 x 10^{12} Btu/yr of energy (uranium ore):

$$\underbrace{0.27\ \text{tons}/10^{12}\ \text{Btu Energy Produced}}_{\text{4th columnar entry, ENVIRONMENTAL RESIDUALS}} \quad \times \quad \underbrace{115 \times 10^{12}\ \text{Btu/yr}}_{\text{"Annual Energy Production," FACILITY OPERATING PARAMETERS}} \quad \cong \quad \underbrace{31\ \text{tons/yr}}_{\text{2nd columnar entry, ENVIRONMENTAL RESIDUALS}}$$

The inverse operation applies (division by "Annual Energy Production" expressed in 10^{12} Btu) if you start with an annual data entry and wish to check the corresponding "Per 10^{12} Btu Energy Produced" columnar entry.

For RESOURCES USED and COSTS, totals are given for construction materials, land resources, construction personnel, and construction costs instead of annualized quantities, because these items are of a nonrecurring nature when referring to energy system lifetime.

The tabular entry "Not Determined" indicates that information was either insufficient or not available to properly quantify that particular entry. In some cases, an explanation is inserted where data are missing.

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NUCLEAR TECHNOLOGIES

OPEN PIT URANIUM MINING

REFERENCE ENERGY SYSTEM

Open pit mining is conducted when the ore body lies under relatively friable material at depths to 120 m. The components of the mining operation include onsite support facilities such as offices and warehouses, mine water pumped into local surface drainage or holding ponds, and mine spoils and ore storage areas.

FACILITY OPERATING PARAMETERS

Size:	528 × 10^3 tons/yr (average ore grade 0.2% U_3O_8)
Annual Capacity Factor:	80%
Annual Energy Production:	115 × 10^{12} Btu
Efficiency:	80% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Energy				
Electricity	1.32 × 10^3 MWh	1.32 × 10^3 MWh	11.5 MWh	
Diesel fuel and lubricants	1.46 × 10^6 gal	5.53 × 10^6 l	12.7 × 10^3 gal	
Processing Materials				
Explosives		Not Determined		
Water				
Mine water from dewatering	2.00 × 10^3 acre-ft	2.46 × 10^9 l	17.3 acre-ft	
Sprays for dust control		Not Determined		
	Total Usage			
Construction Materials				
Concrete	16 tons	15 tonnes	0.14 ton	
Total steel and castings	3.73 × 10^3 tons	3.38 × 10^3 tonnes	32.40 tons	
Copper, brass, and bronze	46 tons	42 tonnes	0.40 ton	
Aluminum and castings	22 tons	20 tonnes	0.19 ton	
Manganese	17 tons	16 tonnes	0.15 ton	
Chromium	8 tons	7 tonnes	0.07 ton	
Nickel	0.23 ton	0.21 tonne	0.002 ton	
Cast iron	155 tons	141 tonnes	1.35 tons	
Land	300 acres	120 ha	2.6 acres	
Personnel				
Construction (4 yr)	115 workers		1 worker	
Operation and maintenance	400 workers		3.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (4 yr)	$59.4 × 10^6 total	$0.517 × 10^6 total	
Operation and maintenance	$22.8 × 10^6/yr	$0.198 × 10^6/yr	
Environmental Controls			
Diversion of surface waters	Not Determined		
Water spraying for dust control	↓		
Revegetation	↓		

OPEN PIT URANIUM MINING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	31 tons	28 tonnes	0.27 ton	
Sulfur dioxide	49 tons	45 tonnes	0.43 ton	
Oxides of nitrogen	29 tons	26 tonnes	0.25 ton	
Hydrocarbons	2.3 tons	2.1 tonnes	0.02 ton	
Carbon monoxide	0.12 ton	0.10 tonne	0.001 ton	
Radon and radon daughters	3.37×10^3 Ci	3.37×10^3 Ci	29.3 Ci	
Water Pollutants				
Suspended solids		Not Determined		
Dissolved solids		↓		
Trace elements				
Solid Wastes				
Overburden moved	16×10^6 tons	15×10^6 tonnes	0.14×10^6 tons	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Uranium ore	0.53×10^6 tons	0.48×10^6 tonnes	4.6×10^3 tons	
U_3O_8 concentrate	1.06×10^3 tons	960 tonnes	9.2 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

UNDERGROUND URANIUM MINING

REFERENCE ENERGY SYSTEM

Operations are for deposits at depths greater than 120 m or when the ore lies under rock requiring blasting. The energy system includes the following onsite support facilities: offices, shops, warehouses, mine spoils area, ore storage, mine shafts, and tunnels.

FACILITY OPERATING PARAMETERS

Size:	0.15×10^6 tons/yr (average ore grade 0.2% U_3O_8)
Annual Capacity Factor:	80%
Annual Energy Production:	32.6×10^{12} Btu
Efficiency:	80% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Energy				
Electricity	9.49×10^3 MWh	9.49×10^3 MWh	291 MWh	
Natural gas	36×10^6 scf	1.0×10^6 m^3	1.1×10^6 scf	
Diesel fuel	59×10^3 gal	220×10^3 l	1.8×10^3 gal	
Processing Materials				
Explosives		Not Determined		
Water				
Domestic use	6 acre-ft	8×10^6 l	0.2 acre-ft	
Mine water from dewatering		Not Determined		
	Total Usage			
Construction Materials				
Concrete	4.79×10^3 tons	4.35×10^3 tonnes	147 tons	
Total steel and castings	3.07×10^3 tons	2.78×10^3 tonnes	94.1 tons	
Copper, brass, and bronze	18 tons	16 tonnes	0.55 ton	
Aluminum and castings	12 tons	11 tonnes	0.37 ton	
Manganese	15 tons	14 tonnes	0.46 ton	
Chromium	2.3 tons	2.1 tonnes	0.07 ton	
Nickel	0.1 ton	0.09 tonne	0.003 ton	
Cast iron	42.4 tons	38.5 tonnes	1.30 tons	
Land	3.9 acres	1.6 ha	0.12 acre	
Personnel				
Construction (3 yr)	36 workers		1.1 workers	
Operation and maintenance	400 workers		12.3 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility	(1978 $)		
Construction (3 yr)	$34.1 × 10^6 total	$1.045 × 10^6 total	
Operation and maintenance	$14.0 × 10^6/yr	$0.429 × 10^6/yr	
Environmental Controls			
Water spraying for dust control	Not Determined		
Mine water purification/uranium recovery	↓		
Grouting/sealing of mine walls	↓		
Ventilation air	↓		

UNDERGROUND URANIUM MINING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	0.33 ton	0.30 tonne	0.01 ton	
Sulfur dioxide	0.7 ton	0.6 tonne	0.02 ton	
Oxides of nitrogen	10 tons	9.5 tonnes	0.32 ton	
Hydrocarbons	1 ton	0.9 tonne	0.03 ton	
Carbon monoxide	6.2 tons	5.6 tonnes	0.19 ton	
Carbon dioxide	620 tons	560 tonnes	19.0 tons	
Aldehydes	0.1 ton	0.09 tonne	0.003 ton	
Organic acids	0.1 ton	0.09 tonne	0.003 ton	
Radon and radon daughters	8.00×10^3 Ci	8.00×10^3 Ci	245 Ci	
Water Pollutants				
Suspended solids		Not Determined		
Dissolved solids		↓		
Radon gas				
Polonium				
Lead				
Bismuth				
Trace elements				
Solid Wastes				
Waste rock	3.9×10^6 ft^3	0.11×10^6 m^3	0.12×10^6 ft^3	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Uranium ore	0.15×10^6 tons	0.14×10^6 tonnes	4.6×10^3 tons	
U_3O_8	300 tons	270 tonnes	9.2 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

URANIUM HEXAFLUORIDE CONVERSION

REFERENCE ENERGY SYSTEM

Conversion of "yellowcake" uranium concentrate into a volatile uranium hexafluoride compound for enrichment by the gaseous diffusion process; uranium hexafluoride conversion by either the dry hydrofluor process or the wet solvent exchange process; offgas treatment to minimize airborne residuals; neutralization and impoundment of liquid wastes.

FACILITY OPERATING PARAMETERS

Size:	5.5 × 10^3 tons/yr (actual output)
Annual Capacity Factor:	80%
Annual Energy Production:	655 × 10^{12} Btu
Efficiency:	100% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Yellowcake (75% U_3O_8)	7.34 × 10^3 tons	6.66 × 10^3 tonnes	11.2 tons	
U_3O_8 (purified)	5.5 × 10^3 tons	5.0 × 10^3 tonnes	8.4 tons	
Energy				
Electricity	46 × 10^3 MWh	46 × 10^3 MWh	71 MWh	
Natural gas	540 × 10^6 scf	15 × 10^6 m^3	0.83 × 10^6 scf	
Processing Materials				
Nitric acid		Not Determined ↓		
Tributylphosphate				
Hexane				
Anhydrous ammonia				
Hydrofluoric acid				
Fluorine				
Water				
Discharged to air	0.28 × 10^3 acre-ft	0.34 × 10^9 l	0.42 acre-ft	
Discharged to water	1.92 × 10^3 acre-ft	2.38 × 10^9 l	2.94 acre-ft	
Total	2.20 × 10^3 acre-ft	2.72 × 10^9 l	3.36 acre-ft	
	Total Usage			
Construction Materials				
Concrete	259 × 10^3 tons	235 × 10^3 tonnes	395 tons	
Steel and castings	8.19 × 10^3 tons	7.43 × 10^3 tonnes	12.5 tons	
Copper, brass, and bronze	120 tons	110 tonnes	0.19 ton	
Aluminum and castings	39 tons	36 tonnes	0.06 ton	
Manganese	39 tons	36 tonnes	0.06 ton	
Chromium	39 tons	36 tonnes	0.06 ton	
Nickel	7 tons	6 tonnes	0.01 ton	
Cast iron	98 tons	89 tonnes	0.15 ton	
Pumps and drivers	7 × 10^3 hp	5 × 10^6 W	0.01 × 10^3 hp	
Heat exchangers	30 × 10^3 ft^3	3 × 10^3 m^2	0.05 × 10^3 ft^2	
Nonnuclear pressure vessel	220 tons	200 tonnes	0.33 ton	
Land	65 acres	27 ha	0.10 acre	
Personnel				
Construction (3 yr)	200 workers		0.3 worker	
Operation and maintenance	300 workers		0.4 worker	

URANIUM HEXAFLUORIDE CONVERSION

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (3 yr)	$55.2 × 10^6 total	$0.0843 × 10^6 total	
Operation and maintenance	$16 × 10^6/yr	$0.024 × 10^6/yr	
Environmental Controls			
Fluorine scrubbers	Not Determined		
Raffinate/waste ponds	↓		
Offgas filters/traps			

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	850 tons	770 tonnes	1.3 tons	
Oxides of nitrogen	300 tons	270 tonnes	0.46 ton	
Hydrocarbons	30 tons	20 tonnes	0.04 ton	
Carbon monoxide	7 tons	6 tonnes	0.01 ton	
Fluoride	3.3 tons	3.0 tonnes	0.005 ton	
Uranium	4.1×10^{-3} Ci	4.1×10^{-3} Ci	6.2×10^{-6} Ci	
Radon and radon daughters		Not Determined		10 CFR 20 specifies allowable levels
Water Pollutants				
Fluoride	790 tons	710 tonnes	1.2 tons	
Sulfate	140 tons	120 tonnes	0.21 ton	
Nitrate	7 tons	6 tonnes	0.01 ton	
Chloride	7 tons	6 tonnes	0.01 ton	
Sodium	105 tons	95 tonnes	0.16 ton	
Ammonium	50 tons	40 tonnes	0.07 ton	
Iron	1.3 tons	1.2 tonnes	0.002 ton	
Radium-226	92×10^{-3} Ci	92×10^{-3} Ci	0.14×10^{-3} Ci	10 CFR 20 specifies allowable levels
Thorium-230	41×10^{-3} Ci	41×10^{-3} Ci	0.063×10^{-3} Ci	
Uranium	1.2 Ci	1.2 Ci	1.8×10^{-3} Ci	
Solid Wastes				
Solid chemical effluents (nonvolatile ash containing iron, calcium, magnesium, copper, fluoride)	1.2×10^3 tons	1.1×10^3 tonnes	1.8 tons	
Low and intermediate level radioactive (buried)	24 Ci	24 Ci	36×10^{-3} Ci	
Thermal Discharge				
Heat discharged to air	0.54×10^{12} Btu	0.57×10^{15} J	0.83×10^9 Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Uranium hexafluoride	5.5×10^3 tons	5.0×10^3 tonnes	8.4 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

URANIUM ENRICHMENT GASEOUS DIFFUSION

REFERENCE ENERGY SYSTEM

Gaseous diffusion enrichment plant using porous barriers and compressors arranged in series to produce uranium hexafluoride enriched to 4% uranium-235; onsite support facilities; tails storage; settling/neutralization ponds; waste burial grounds; feed vaporization and product recovery systems; steam plant.

FACILITY OPERATING PARAMETERS

Size:	12×10^3 tons/yr (enriched uranium-235 as uranium hexafluoride; tails assay 0.2% uranium)
Annual Capacity Factor:	80%
Annual Energy Production:	2190×10^{12} Btu
Efficiency:	65.4% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium hexafluoride (unenriched)	18×10^3 tons	17×10^3 tonnes	8.4 tons	
Energy				
Electricity	28×10^6 MWh	28×10^6 MWh	13×10^3 MWh	
Water				
Discharged to air	23×10^3 acre-ft	29×10^9 l	11 acre-ft	
Discharged to water bodies (at diffusion plant)	1.8×10^3 acre-ft	22×10^9 l	0.8 acre-ft	
Discharged to water bodies (at power plant)	3.07×10^6 acre-ft	3.8×10^{12} l	1.4×10^3 acre-ft	
	Total Usage			
Construction Materials				
Concrete	1670×10^3 tons	1510×10^3 tonnes	760 tons	
Total steel and castings	723×10^3 tons	656×10^3 tonnes	330 tons	
Copper, brass, and bronze	25.6×10^3 tons	23.3×10^3 tonnes	11.7 tons	
Aluminum and castings	16×10^3 tons	15×10^3 tonnes	7.5 tons	
Manganese	3.9×10^3 tons	3.6×10^3 tonnes	1.8 tons	
Chromium	5.0×10^3 tons	4.6×10^3 tonnes	2.3 tons	
Nickel	0.90×10^3 tons	0.82×10^3 tonnes	0.41 ton	
Cast iron	58.0×10^3 tons	52.7×10^3 tonnes	26.5 tons	
Steam turbogenerators	520 MWe	520 MWe	0.24 MWe	
Pumps and drivers	590×10^3 hp	440×10^6 W	0.27×10^3 hp	
Axial compressor	8300×10^3 hp	6200×10^6 W	3.8×10^3 hp	
Centrifuge compressors and drivers	22 tons	20 tonnes	0.01 ton	
Heat exchangers	7.9×10^6 ft^2	730×10^3 m^2	3.6×10^3 ft^2	
Land				
		Not Determined		
Personnel				
Construction (8 yr)	6.1×10^3 workers		2.8 workers	
Operation and maintenance	2.2×10^3 workers		1.0 worker	

URANIUM ENRICHMENT GASEOUS DIFFUSION

COSTS	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility	(1978 \$)		
Construction (8 yr)	\$11.5 × 10^9 total	\$5.24 × 10^6 total	
Operation and maintenance	\$770 × 10^6/yr	\$0.35 × 10^6/yr	
Environmental Controls			
Cooling towers	Not Determined		
Liquid waste systems	↓		
Neutralization pond			
Filters			
Fluorine scrubber			

ENVIRONMENTAL RESIDUALS	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	113 × 10^3 tons	103 × 10^3 tonnes	51.8 tons	
Sulfur dioxide	431 × 10^3 tons	392 × 10^3 tonnes	197 tons	
Oxides of nitrogen	113 × 10^3 tons	103 × 10^3 tonnes	51.8 tons	
Hydrocarbons	1.1 × 10^3 tons	1.0 × 10^3 tonnes	0.5 ton	
Carbon monoxide	2.8 × 10^3 tons	2.6 × 10^3 tonnes	1.3 tons	
Fluoride	0.044 × 10^3 tons	0.04 × 10^3 tonnes	0.02 ton	
Uranium	0.18 Ci	0.18 Ci	83 × 10^{-6} Ci	
Technetium-99	0.74 Ci	0.74 Ci	0.34 × 10^{-3} Ci	
Ruthenium-106	0.010 Ci	0.010 Ci	4.6 × 10^{-6} Ci	
Water Pollutants				
Calcium	700 tons	600 tonnes	0.3 ton	
Chloride	900 tons	800 tonnes	0.4 ton	
Sodium^{+}	900 tons	800 tonnes	0.4 ton	
Sulfate	700 tons	600 tonnes	0.3 ton	
Iron	44 tons	40 tonnes	0.02 ton	
Nitrate	260 tons	240 tonnes	0.12 ton	
Uranium	1.8 Ci	1.8 Ci	0.83 × 10^{-3} Ci	
Technetium-99	9.6 Ci	9.6 Ci	4.4 × 10^{-3} Ci	
Solid Wastes				
Equipment components		Not Determined		
Sludges		↓		
Thermal Discharge				
Heat discharged to water	226 × 10^{12} Btu	238 × 10^{15} J	103 × 10^9 Btu	
Heat discharged to air	68 × 10^{12} Btu	72 × 10^{15} J	31 × 10^9 Btu	
Noise Pollution				
In-plant		Not Determined		
Cooling tower		↓		

PRODUCTS	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Enriched uranium-235 in uranium hexafluoride	12.0 × 10^3 tons	10.9 × 10^3 tonnes	5.49 tons	
Byproducts				
Uranium-235 in tails	22 tons	20 tonnes	0.01 ton	Tails 0.2% uranium

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

URANIUM ENRICHMENT GAS CENTRIFUGE

REFERENCE ENERGY SYSTEM

The gas centrifuge enrichment process uses a system of centrifuges to enrich uranium in uranium-235 to 2-4%. System components include production facilities; feed, product, and tails withdrawal systems; decontamination facilities; recirculating and sanitary water systems; sewage systems; etc.

FACILITY OPERATING PARAMETERS

Size:	10 × 10^3 tons/yr (tails assay 0.2%)
Annual Capacity Factor:	80%
Annual Energy Production:	1821 × 10^{12} Btu
Efficiency:	65.4%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium hexafluoride	15 × 10^3 tons	14 × 10^3 tonnes	8.4 tons	
Energy				
Coal	66.8 × 10^3 tons	60.7 × 10^3 tonnes	36.7 tons	Heating and process steam
Gasoline and diesel fuel	208 × 10^3 gal	786 × 10^3 l	114 gal	
Electricity	2.0 × 10^6 MWh	2.0 × 10^6 MWh	1.1 × 10^3 MWh	
Water				
Discharged to air	890 acre-ft	1.1 × 10^9 l	0.49 acre-ft	
Discharged to water	1.82 × 10^3 acre-ft	2.24 × 10^9 l	1.00 acre-ft	
	Total Usage			
Construction Materials				
Concrete	600 × 10^3 tons	540 × 10^3 tonnes	330.00 tons	
Steel	280 × 10^3 tons	250 × 10^3 tonnes	151.00 tons	
Aluminum	25 × 10^3 tons	23 × 10^3 tonnes	14.00 tons	
Copper	4.9 × 10^3 tons	4.5 × 10^3 tonnes	2.70 tons	
Zinc	0.22 × 10^3 tons	0.20 × 10^3 tonnes	0.12 ton	
Transformer cooling oil	0.33 × 10^3 tons	0.30 × 10^3 tonnes	0.18 ton	
Paving materials	1.3 × 10^3 tons	1.2 × 10^3 tonnes	0.70 ton	
Miscellaneous metal products	1.2 × 10^3 tons	1.0 × 10^3 tonnes	0.63 ton	
Land	840 acres	340 ha	0.46 acre	
Personnel				
Construction (7 yr)	5.1 × 10^3 workers		2.8 workers	
Operation and maintenance	1.8 × 10^3 workers		1.0 worker	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1975$)		
Construction (7 yr)	$3.57 × 10^9 total	$1.96 × 10^6 total	
Operation and maintenance	$473 × 10^6/yr	$0.260 × 10^6/yr	
Environmental Controls			
Filters	Not Determined ↓		
Liquid waste processing			
Neutralization facilities			
Cooling towers			
Fluorine scrubbers			

URANIUM ENRICHMENT GAS CENTRIFUGE

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	40 tons	30 tonnes	0.02 ton	
Sulfur dioxide	840 tons	760 tonnes	0.46 ton	
Oxides of nitrogen	670 tons	610 tonnes	0.37 ton	
Hydrocarbons		Negligible		
Carbon monoxide	18 tons	16 tonnes	0.01 ton	
Uranium (total isotopes)	56×10^{-3} Ci	56×10^{-3} Ci	31×10^{-6} Ci	
Water Pollutants				
Condensate				
• Water	3.70×10^{3} tons	3.36×10^{3} tonnes	2.03 tons	
Aqueous waste				
• Water	560 tons	510 tonnes	0.31 ton	
• Nitric acid	90 tons	80 tonnes	0.05 ton	
• Aluminum nitrate	110 tons	100 tonnes	0.06 ton	
Noncondensable gas				
• Oxides of nitrogen	1.8 tons	1.6 tonnes	0.001 ton	
Radiation				
• Uranium (total isotopes)	6.0×10^{-3} Ci	6.0×10^{-3} Ci	3.3×10^{-6} Ci	
Solid Wastes				
Failed rotors		Not Determined		
Thermal Discharge				
Heat dissipated from steam plant	360×10^{9} Btu	380×10^{12} J	0.2×10^{9} Btu	
Noise Polllution				
In-plant		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Enriched uranium-235 in uranium hexafluoride	1.00×10^{3} tons	9.08×10^{3} tonnes	5.49 tons	
Byproducts				
Uranium-235 in tails	18 tons	16 tonnes	0.01 ton	0.2% uranium in tails

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BEST DOCUMENT AVAILABLE

FUEL FABRICATION PLANT

REFERENCE ENERGY SYSTEM

Fuel fabrication is accomplished by chemical conversion of uranium hexafluoride to uranium dioxide and mechanical processing including pellet production and fuel element fabrication loaded in zircalloy or stainless steel tubes, fitted with end caps, and welded.

FACILITY OPERATING PARAMETERS

Size:	990 tons/yr
Annual Capacity Factor:	80%
Annual Energy Production:	619 × 10^{12} Btu
Efficiency:	100% (uranium-235 output vs. uranium-235 input)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium-235 enriched in uranium hexafluoride	3.40 × 10^3 tons	3.08 × 10^3 tonnes	5.49 tons	
Energy				
Electricity	44 × 10^3 MWh	44 × 10^3 MWh	71 MWh	
Natural gas	93 × 10^6 scf	2.6 × 10^6 m^3	0.15 × 10^6 scf	
Processing Materials				
Aqueous ammonia		Not Determined		
Nitric acid (70%)		↓		
Sodium hydroxide (50%)		↓		
Sulfuric acid (70%)		↓		
Water				
Discharged to water	410 acre-ft	510 × 10^6 l	0.67 acre-ft	
	Total Usage			
Construction Materials				
Concrete	46.2 × 10^3 - 275 × 10^3 tons	42.0 × 10^3 - 250 × 10^3 tonnes	74.70–444.0 tons	
Total steel and castings	7.43 × 10^3 - 27.8 × 10^3 tons	6.74 × 10^3 - 25.3 × 10^3 tonnes	12.00–45.00 tons	
Copper, brass, and bronze	360 - 3.22 × 10^3 tons	330 - 2.92 × 10^3 tonnes	0.59–5.20 tons	
Aluminum and castings	170–885 tons	150–800 tonnes	0.27–1.43 tons	
Manganese	50–130 tons	40–120 tonnes	0.08–0.21 ton	
Chromium	62–93 tons	56–84 tonnes	0.10–0.15 ton	
Nickel	12–18 tons	11–17 tonnes	0.02–0.03 ton	
Cast iron	300–560 tons	280–510 tonnes	0.49–0.90 ton	
Steam turbines	0 - 6.2 × 10^3 hp	0 - 4.6 × 10^6 W	0–10 hp	
Pumps and drivers	6.2 × 10^3 - 25 × 10^3 hp	4.6 × 10^6 - 18 × 10^6 W	10–40 hp	
Heat exchangers	0 - 18 × 10^3 ft^2	0 - 1.7 × 10^3 m^2	0–30 ft^2	
Land	7.4 acres	3.0 ha	0.012 acre	
Personnal				
Construction (2–3 yr)	400–2.1 × 10^3 workers		0.7–3.4 workers	
Operation and maintenance	990–2.1 × 10^3 workers		1.6–3.4 workers	

FUEL FABRICATION PLANT

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (2-3 yr)	$155 × 10^6 - 496 × 10^6 total	$0.250 × 10^6 - 0.801 × 10^6 total	
Operation and maintenance	$111 × 10^6 - 161 × 10^6/yr	$0.180 × 10^6 - 0.260 × 10^6/yr	
Environmental Controls			
High-efficiency particulate aerosol filter system	Not Determined		
Scrubbers and dryers	↓		
Waste lagoons	↓		
Sanitary waste system	↓		

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	681 tons	618 tonnes	1.10 tons	
Oxides of nitrogen	170 tons	160 tonnes	0.28 ton	
Carbon monoxide	6.2 tons	5.6 tonnes	0.01 ton	
Uranium	5.1×10^{-3} Ci	5.1×10^{-3} Ci	8.3×10^{-6} Ci	
Water Pollutants				
Nitrogen as ammonia	280 tons	260 tonnes	0.46 ton	
Nitrogen as nitrate	681 tons	618 tonnes	1.10 tons	
Fluoride	120 tons	110 tonnes	0.19 ton	
Uranium	0.51 Ci	0.51 Ci	0.83×10^{-3} Ci	
Thorium-234	0.26 Ci	0.26 Ci	0.42×10^{-3} Ci	
Solid Wastes				
Calcium fluoride	743 tons	674 tonnes	1.20 tons	
Ammonia		Not Determined		
Fluorine		↓		
Sulfur oxide		↓		
Nitrate		↓		
Uranium (buried)	5.9 Ci	5.9 Ci	9.6×10^{-3} Ci	
Thermal Discharge				
Heat dissipated	200 × 10^9 Btu	300 × 10^{12} J	0.4 × 10^9 Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Uranium (uranium dioxide) fuel elements	990 tons	900 tonnes	1.6 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BEST DOCUMENT AVAILABLE

PRESSURIZED WATER REACTOR NUCLEAR POWER PLANT

REFERENCE ENERGY SYSTEM

Pressurized water reactor nuclear-powered electric generating plant using 3.3% enriched uranium-235 fuel; onsite storage of spent reactor fuel; maximum recycling of liquid radioactive wastes; filtration of building exhausts; onsite water treatment of river supply water; natural draft wet cooling towers.

FACILITY OPERATING PARAMETERS

Size:	1×10^3 MWe
Annual Capacity Factor:	70%
Annual Energy Production:	21×10^{12} Btu (6.13×10^6 MWh)
Efficiency:	30%
Lifetime:	30–40 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium fuel (3.3% uranium-235)	26.7 tons	24.2 tonnes	1.27 tons	33% of core annually
Water				
Power plant make-up water	16×10^3 acre-ft	19×10^9 l	0.74×10^3 acre-ft	
	Total Usage			
Construction Materials				
Concrete	250×10^3 yd^3	190×10^3 m^3	11.9×10^3 yd^3	
Metal conduit	500×10^3 ft	150×10^3 m	24×10^3 ft	
Cable tray	100×10^3 ft	30×10^3 m	4.8×10^3 ft	
Large process pipe	160×10^3 ft	50×10^3 m	7.6×10^3 ft	
Small pipe	200×10^3 ft	60×10^3 m	9.5×10^3 ft	
Wire and cable	7×10^6 ft	2.1×10^6 m	0.3×10^6 ft	
Land				
Site area	1.85×10^3 acres	749 ha	88.1 acres	
Low-level radioactive waste disposal area	0.02 acre	0.008 ha	0.9×10^{-3} acre	
Personnel				
Construction (9 yr)	2.31×10^3 workers		110 workers	
Operation and maintenance	230 workers		11 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction (9 yr)			Total life-cycle costs = 65.9 mills/kWh (1976 $)
Operation and maintenance			
Environmental Controls			Included in facility costs

PRESSURIZED WATER REACTOR NUCLEAR POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Noble gases	1.80×10^3 Ci	1.80×10^3 Ci	85.7 Ci	10 CFR 50 and 40 CFR 190 specify individual concentration limits
Carbon-14	6.2 Ci	6.2 Ci	0.30 Ci	
Tritium	800 Ci	800 Ci	38.1 Ci	
Fossil fuel air emissions	53 tons	48 tonnes	2.5 tons	
Airborne water from cooling tower evaporation losses	3.8×10^9 gal	14.4×10^9 l	0.18×10^9 gal	
Water Pollutants				
Activated corrosion and fission products	0.12 Ci	0.12 Ci	0.006 Ci	10 CFR 50 and 40 CFR 190 specify individual concentration limits
Tritium	302 Ci	302 Ci	14.4 Ci	
Total suspended solids	Metric units are universally used	12.9×10^3 mg/l	Depends on flow, which varies widely	40 CFR 423 specifies allowable increases in river concentrations
Total dissolved solids		2860 mg/l		
Iron		180 mg/l		
Chloride		360 mg/l		
Chromium		0.30 mg/l		
Copper		0.73 mg/l		
Zinc		0.84 mg/l		
Solid Wastes				
Low level solid radwaste	5.83×10^3 Ci (5.90×10^3 ft^3)	5.83×10^3 Ci (167 m^3)	278 Ci (280 ft^3)	
Thermal Discharge				
Heat dissipated to atmosphere	42×10^{12} Btu	44×10^{15} J	2×10^{12} Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	6.1×10^6 MWh	6.1×10^6 MWh	0.29×10^6 MWh	
Recoverables/Recyclables				
Spent nuclear fuel	26.7 tons	24.3 tonnes	1.30 tons	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	0	0	
Injuries	0.5–3.0	0.02–0.14	
Radiation Exposure	428 man-rem	20.4 man-rem	

BOILING WATER REACTOR NUCLEAR POWER PLANT

REFERENCE ENERGY SYSTEM

The General Electric Company's standardized BWR/6 reactor with the Mark III containment design. Natural draft cooling towers.

FACILITY OPERATING PARAMETERS

Size:	1000 MWe
Annual Capacity Factor:	70%
Annual Energy Production:	21 × 10^{12} Btu
Efficiency:	33%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium fuel (3.0% uranium-235 enriched)	34 tons	31 tonnes	1.6 tons	One-fourth of core annually
Processing Materials				
Water				
Make-up water for cooling towers and miscellaneous plant services	25 × 10^3 acre-ft	30 × 10^9 l	1.2 × 10^3 acre-ft	
	Total Usage			
Construction Materials				
Concrete	4.5 × 10^6 ft^3	130 × 10^3 m^3	210 × 10^3 ft^3	
Reinforcing steel	17 × 10^3 tons	15 × 10^3 tonnes	810 tons	
Structural steel	8.7 × 10^3 tons	7.9 × 10^3 tonnes	420 tons	
			Per 10^{12} Btu Energy Capacity	
Land*				
Site land requirements	1100 ± 900 acres	450 ± 360 ha	21 ± 17 acres	
Transmission route	1800 ± 2200 acres	730 ± 890 ha	34 ± 42 acres	
Disrupted land surface (site)	350 ± 610 acres	140 ± 250 ha	6.7 ± 3.0 acres	
Committed land	130 ± 100 acres	53 ± 40 ha	2.5 ± 1.9 acres	
Personnel				
Construction (9 yr)	480 workers		22.8 workers	9.5 × 10^6 man-hour for craft labor; average work force of 3000
Operation and maintenance	Not Determined			

*For two 1250-MWe units with cooling towers.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1981 $)		
Construction (9 yr) (with interest during construction)	$1.0 × 10^9 total	$48 × 10^6 total	
Operation and maintenance	$77 × 10^6/yr	$0.81 × 10^6/yr	
Environmental Controls	Not Determined		

BEST DOCUMENT AVAILABLE

BOILING WATER REACTOR NUCLEAR POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Gaseous radioactive effluents				
• Noble gases	11.3×10^3 Ci	11.3×10^3 Ci	540 Ci	
• Tritium	110 Ci	110 Ci	5.2 Ci	
• Carbon-14	6.8 Ci	6.8 Ci	0.32 Ci	
• Iodine-131 (elemental)	64×10^{-3} Ci	64×10^{-3} Ci	3.0×10^{-3} Ci	
• Iodine-131 (nonelemental)	140×10^{-3} Ci	140×10^{-3} Ci	6.6×10^{-3} Ci	
Combustion emissions				
• Sulfur oxides	20 tons	18 tonnes	0.95 ton	
• Carbon monoxide	98 tons	89 tonnes	4.7 tons	
• Nitrogen oxides	70 tons	63 tonnes	3.3 tons	
Water Pollutants				
Liquid radioactive effluents				
• Tritium	14 Ci	14 Ci	0.67 Ci	
• Activation and fission products	0.1 Ci	0.1 Ci	5×10^{-3} Ci	
Dissolved solids				
• Sulfates	23 tons	21 tonnes	1.1 tons	
• Chlorine	0.9 ton	0.8 tonne	0.04 ton	
• Sodium	11 tons	10 tonnes	0.53 ton	
• Other	5.8 tons	5.3 tonnes	0.28 ton	
Solid Wastes				
Low-level solid radioactive wastes				
• Wet material embedded in concrete	19×10^3 ft^3	530 m^3	900 ft^3	
• Dry material in drums	3.3×10^3 ft^3	94 m^3	160 ft^3	
Water filtration waste products				
• Aluminum hydroxide	10 tons	9.1 tonnes	0.48 ton	
• Settled solids	8 tons	7.3 tonnes	0.38 ton	
Thermal Discharge				
Heat dissipated	61×10^{12} Btu	64×10^{15} J	2.9×10^{12} Btu	
Noise Pollution		Negligible		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electric power	6.13×10^9 kWh	6.13×10^9 kWh	2.93×10^8 kWh	
Byproducts		Not Determined		
Recoverables/Recyclables				
Spent nuclear fuel containing				
• Uranium-235 nuclear fuel				
– Mass	616 lb	280 kg	29.3 lb	
– Energy equivalent	4.3×10^9 kWh (14.7×10^{21} Btu)	4.3×10^9 kWh (15.5×10^{24} J)	0.21×10^8 kWh (0.7×10^{21} Btu)	
• Fissile plutonium nuclear fuel				
– Mass	396 lb	180 kg	18.8 lb	
– Energy equivalent	3.4×10^9 kWh (10.5×10^{21} Btu)	3.4×10^9 kWh (11.1×10^{24} J)	1.6×10^8 kWh = 0.5×10^{21} Btu (0.5×10^{21} Btu)	
• Isotopes for medical and industrial applications		Not Determined		

(Continued on next page)

BEST DOCUMENT AVAILABLE

BOILING WATER REACTOR NUCLEAR POWER PLANT

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	0.0	0.0	
Injuries			
Number	0.51-3.0	0.02-0.14	
Total lost days	14-91	0.67-4.33	
Occupational Radiation Exposure	1.1×10^3 man-rems	53 man-rems	Average collective dose

URANIUM MILLING

REFERENCE ENERGY SYSTEM

The model is a uranium mill described by the Nuclear Regulatory Commission in the Final Generic Environmental Impact Statement on Uranium Milling, NUREG-0706, Vol. I-III, September 1980. Tailings control and disposal includes retention basin, clay liner, evaporation pond, in situ solids filtration, and earth cover.

FACILITY OPERATING PARAMETERS

Size:	635 tons/yr uranium concentrate (yellowcake at 90% U_3O_8)
Annual Capacity Factor:	85%
Annual Energy Production:	68.3 × 10^{12} Btu
Efficiency:	93% (recovery)
Lifetime:	15 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium ore (0.1% uranium)	620 × 10^3 tons	560 × 10^3 tonnes	9.1 × 10^3 tons	
Energy[a]				
Electrical	10.8 × 10^3 MWh	10.8 × 10^3 MWh	158 MWh	
Natural gas (process heat)	274 × 10^6 scf	7.76 × 10^6 m^3	4.0 × 10^6 scf	
Processing Materials				
Sulfuric acid	28 × 10^3 tons	25 × 10^3 tonnes	400 tons	
Sodium chlorite	860 tons	780 tonnes	13 tons	
Ammonium	680 tons	610 tonnes	10 tons	
Flocculent	37 tons	34 tonnes	0.54 ton	
Amine	9 tons	8 tonnes	0.1 ton	
Alcohol	25 tons	22 tonnes	0.4 ton	
Kerosene	280 tons	250 tonnes	4 tons	
Iron	150 tons	140 tonnes	2.2 tons	
Water				
Process water	320 acre-ft	390 × 10^6 l	4.7 acre-ft	
	Total Usage			
Construction Materials				
Concrete	250 × 10^3 ft^3	7.0 X $10^3 m^3$	3.7 × 10^3 ft^3	
Steel	1.7 × 10^3 tons	1.6 × 10^3 tonnes	25 tons	
Copper and aluminum	52 tons	47 tonnes	0.76 ton	
Wood	18 tons	16 tonnes	0.26 ton	
Plastics	18 tons	16 tonnes	0.26 ton	
Land				
Mill operations	120 acres	50 ha	1.8 acres	
Tailings	250 acres	100 ha	3.7 acres	
Uncommitted	370 acres	150 ha	5.4 acres	
Total	740 acres	300 ha	10.9 acres	
Personnel				
Construction (5 yr)	120 workers		1.76 workers	
Operation and maintenance	160 workers		2.34 workers	

(Continued on next page)

URANIUM MILLING

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1981 $)		
Construction (5 yr)	37.1×10^6 total	0.54×10^6 total	
Operation and maintenance	$ 8.5 \times 10^6$/yr	0.13×10^6/yr	
Environmental Controls			
Ore crushing/handling wet scrubbers	155×10^3 total	2.3×10^3 total	Total capital costs
	18.6×10^3/yr	0.275×10^3/yr	Operating costs per year
Yellowcake drying wet scrubbers	50.4×10^3 total	0.7×10^3 total	Total capital costs
	6.2×10^3/yr	0.091×10^3/yr	Operating costs per year
Tailings control and disposal	13.7×10^6 total	0.200×10^6 total	Includes capital and total operating costs over lifetime

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	370 tons	340 tonnes	5.4 tons	
Sulfur dioxide	0.34 ton	0.31 tonnes	5.0×10^{-3} ton	
Oxides of nitrogen	28 tons	25 tonnes	0.41 tons	
Kerosene	24 tons	22 tunnes	0.35 ton	
Uranium-238, Uranium-234	0.160 Ci	0.160 Ci	2.3×10^{-3} Ci	
Thorium-230	0.122 Ci	0.122 Ci	1.8×10^{-3} Ci	
Radon	4.5×10^3 Ci	4.5×10^3 Ci	66 Ci	
Water Pollutants				
Water discharged	326 acre-ft	402×10^6 l	4.8 acre-ft	
• Sulfate	13×10^3 tons	12.1×10^3 tonnes	190 tons	
• Iron	440 tons	400 tonnes	6.5 tons	
• Manganese	22 tons	20 tonnes	0.32 ton	
• Selenium	0.88 ton	0.80 tonne	0.01 ton	
Uranium-natural	1.3 Ci	1.3 Ci	19×10^{-3} Ci	
Radium-226	0.1 Ci	0.1 Ci	1.4×10^{-3} Ci	
Thorium-230	36 Ci	36 Ci	0.53 Ci	
Solid Wastes				
Tailings	610×10^3 tons	560×10^3 tonnes	9.0×10^3 tons	
Uranium-natural	21.8 Ci	21.8 Ci	0.32 Ci	
Radium-226	156 Ci	156 Ci	2.3 Ci	
Thorium-230	156 Ci	156 Ci	2.3 Ci	
Lead-210, polonium-210, bismuth-210	0.3 Ci	0.3 Ci	4×10^{-3} Ci	
Thermal Discharge				
Process heat to air	280×10^9 Btu	300×10^{12} J	4.1×10^9 Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Yellowcake (90% U_3O_8)	635 tons	580 tonnes	9.3 tons	
Recoverables/Recyclables				
30% of the tailings liquid	135 acre-ft	166×10^6 l	1.99 acre-ft	

URANIUM MILLING

OCCUPATIONAL SAFETY AND HEALTH[b]

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	0.47	0.007	1977 Data
Injuries	34	0.50	↓

[a] U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle, WASH-1248, 1974.

[b] Oak Ridge National Laboratory, An Integrated Assessment of the Impacts Associated with Uranium Mining and Milling, ORNL/TM-6677, July 1979.

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SYNTHETIC FUEL TECHNOLOGIES

25

H-COAL PROCESS

REFERENCE ENERGY SYSTEM

The reference system is based on conceptual designs and includes mine-mouth coal processing and a conversion plant utilizing mid-western (Illinois No. 6) high sulfur coal to produce liquid hydrocarbon products and other byproducts. Clean process-derived fuel gas is utilized as onsite fuel. Tail gas sulfur recovery is utilized. Solid wastes are returned to the mine. Onsite water treatment and recirculation are utilized to facilitate minimal discharge to surface waters.

FACILITY OPERATING PARAMETERS

Size:	36.5×10^3 bbl/day syncrude, 24.7×10^3 bbl/day naphtha (major energy products)
Annual Capacity Factor:	91.3%
Annual Energy Production:	127.4×10^{12} Btu
Efficiency:	60% (based on total product, byproduct energy content, and onsite power generation)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Run-of-mine mid-western coal	9.28×10^6 tons	8.42×10^6 tonnes	72.8×10^3 tons	Includes onsite power generation; 11.443×10^3 Btu/lb
Processing Materials				
		Not Determined		
Water				
Water consumed (make-up)	18.8×10^3 acre-ft	23.3×10^9 l	148 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land				
Plant	400 acres	160 ha	3.1 acres	
Solid waste disposal		Not Determined		
Personnel				
Construction		Not Determined		
Operation and maintenance	726 workers		5.7 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1975 $)		
Construction	$\$1.15 \times 10^9$ total	$\$9.02 \times 10^6$ total	
Operation and maintenance	$\$245 \times 10^6$/yr	$\$1.92 \times 10^6$/yr	
Environmental Controls			
	Not Determined		

H-COAL PROCESS

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	9.2×10^3 tons	8.3×10^3 tonnes	72 tons	
Oxides of nitrogen	5.2×10^3 tons	4.7×10^3 tonnes	41 tons	
Particulates	0.56×10^3 tons	0.51×10^3 tonnes	4.4 tons	
Hydrocarbons	0.08×10^3 tons	0.07×10^3 tonnes	0.6 ton	
Water Pollutants				
No direct discharge into any water source				Wastewater disposal method not specified
Solid Wastes				
Total solid waste (dry ton equivalent)	0.937×10^6 tons	0.850×10^6 tonnes	7.354×10^3 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Syncrude (low sulfur)	12.1×10^6 bbl	1.93×10^9 l	95.358×10^3 bbl	
Naphtha	8.23×10^6 bbl	1.31×10^9 l	64.578×10^3 bbl	
Byproducts				
Sulfur	0.40×10^6 tons	0.36×10^6 tonnes	3.1×10^3 tons	
Ammonia	0.08×10^6 tons	0.07×10^6 tonnes	0.6×10^3 tons	
Phenols	7.9×10^3 tons	7.2×10^3 tonnes	62 tons	
Electric power	652×10^3 MWh	652×10^3 MWh	5.120×10^3 MWh	
Recoverables/Recyclables				
Recycled water	4.75×10^3 acre-ft	5.86×10^9 l	37.3 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

LURGI PROCESS – LIGNITE COAL

REFERENCE ENERGY SYSTEM

The conceptual reference system includes Lurgi fixed bed gasifiers utilizing North Dakota lignite coal to produce substitute natural gas for pipeline distribution. The gas will be equivalent to natural gas in heating value. The plant includes limestone sulfur dioxide scrubbers, Stretford sulfur recovery gas cleanup units, wastewater treatment, and landfill facilities. 135 MWe auxiliary power is used by the plant.

FACILITY OPERATING PARAMETERS

Size:	275 × 10^6 scf/day (997 Btu/scf)
Annual Capacity Factor:	91%
Annual Energy Production:	91.03 × 10^{12} Btu
Efficiency:	67.3% (based on 135 MWe purchased power and the energy content of the byproduct sulfur)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
North Dakota lignite	9.06 × 10^6 tons	8.22 × 10^6 tonnes	99.5 × 10^3 tons	7.32 × 10^3 Btu/lb
Energy				
Electricity (purchased)	1.00 × 10^9 kWh	1.00 × 10^9 kWh	0.011 × 10^9 kWh	
Processing Materials		Not Determined		
Water				
Consumptive	1.76 × 10^3 acre-ft	2.17 × 10^9 l	19.3 acre-ft	Gasification only
	Total Usage			
Construction Materials		Not Determined		
Land	540 acres	220 ha	5.9 acres	
Personnel				
Construction (9 yr)	790 workers		8.7 workers	
Operation and maintenance (30 yr)	640 workers		7.0 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction (3 yr)	Not Determined		
Operation and maintenance	↓		
Environmental Controls	Not Determined		

LURGI PROCESS – LIGNITE COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	24.1×10^3 tons	21.8×10^3 tonnes	264.3 tons	
Oxides of nitrogen	58.4×10^3 tons	53.0×10^3 tonnes	641.9 tons	
Particulates	2.75×10^3 tons	2.50×10^3 tonnes	30.2 tons	
Hydrocarbons		Not Determined		
Carbon monoxide		↓		
Water Pollutants				
Deep-well disposal	730×10^3 bbl	116×10^6 l	8.0×10^3 bbl	
Solid Wastes				
Gasifier ash	0.586×10^6 tons	0.532×10^6 tonnes	6.435×10^3 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Substitute natural gas	91×10^9 scf	2.6×10^9 m^3	1.0×10^9 scf	997 Btu/scf
Byproducts				
Sulfur	0.12×10^6 tons	0.11×10^6 tonnes	1.3×10^3 tons	
Recoverables/Recyclables				
Tar	0.32×10^6 tons	0.29×10^6 tonnes	3.5×10^3 tons	
Tar oil	0.11×10^6 tons	0.10×10^6 tonnes	1.2×10^3 tons	
Naphtha	0.05×10^6 tons	0.04×10^6 tonnes	0.5×10^3 tons	
Phenol	0.07×10^6 tons	0.06×10^6 tonnes	0.8×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SURFACE OIL SHALE MINING

REFERENCE ENERGY SYSTEM

In surface oil shale mining, bench configuration is used for overburden removal and shale extraction. Shale is drilled, blasted, and transported by truck from the in-mine site to a primary crushing site. Shale mined is assumed to be 2800 Btu/lb of raw shale or 30 gal/ton shale oil content.

FACILITY OPERATING PARAMETERS

Size:	73.7 × 10^3 tons/day (raw shale mined)
Annual Capacity Factor:	90%
Annual Energy Production:	135.6 × 10^{12} Btu
Efficiency:	Not determined
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw shale	24.1 × 10^6 tons	22.0 × 10^6 tonnes	178 × 10^3 tons	
Energy		Not Determined		
Processing Materials		Not Determined		
Water	300–450 acre-ft	370 × 10^6 - 550 × 10^6 l	2.2–3.3 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land	1.44 × 10^3 acres	582 ha	10.6 acres	
Personnel				
Construction		Not Determined		
Operation and maintenance		↓		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$82.7 × 10^6 total	$0.610 × 10^6 total	
Operation and maintenance	Not Determined		
Environmental Controls			
Water spray to control dust	Not Determined		

SURFACE OIL SHALE MINING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	3.0×10^3 tons	2.7×10^3 tonnes	22 tons	
Sulfur dioxide	28 tons	26 tonnes	0.21 ton	
Oxides of nitrogen	400 tons	363 tonnes	2.95 tons	
Hydrocarbons	466 tons	423 tonnes	3.44 tons	
Carbon monoxide	244 tons	222 tonnes	1.80 tons	
Water Pollutants				
Possibility of underground water contamination by saline mine water				
Solid Wastes				
		Negligible		See oil shale surface retorting
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Mined and primary crushed oil shale rock	24.1×10^6 tons	22.0×10^6 tonnes	178×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

UNDERGROUND OIL SHALE MINING

REFERENCE ENERGY SYSTEM

Underground oil shale mine utilizing room and pillar configuration for shale removal. The oil shale is entered through a tunnel dug into the side of a valley where an outcrop appears. Pillars are left in place to provide roof support. The shale is drilled and blasted and transported to a portable underground primary crusher. The crushed shale is then taken above ground by a conveyor system and crushed further. 30 gal of shale oil produced per ton of shale mined.

FACILITY OPERATING PARAMETERS

Size:	73.7 × 10^3 tons/day raw shale mined
Annual Capacity Factor:	90%
Annual Energy Production:	135.57 × 10^{12} Btu
Efficiency:	Not determined
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw shale (unmined)	24.2 × 10^6 tons	22.0 × 10^6 tonnes	178.45 × 10^3 tons	
Energy				
Electricity for mine equipment	Not Determined			
Water				
Mining and crushing	300–450 acre-ft	380 × 10^6 - 550 × 10^6 l	2.3-3.3 acre-ft	
	Total Usage			
Construction Materials	Not Determined			
Land	418 acres	169 ha	3.08 acres	
Personnel				
Construction	484 workers		3.57 workers	
Operation and maintenance	Not Determined			

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility	(1978 $)		
Construction	$73.9 × 10^6 total	$0.545 × 10^6 total	
Operation and maintenance	Not Determined		
Environmental Controls	Not Determined		

UNDERGROUND OIL SHALE MINING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	605 tons	549 tonnes	4.46 tons	
Sulfur dioxide	1.6 tons	1.5 tonnes	0.012 ton	
Oxides of nitrogen	23 tons	21 tonnes	0.17 ton	
Hydrocarbons	2.6 tons	2.4 tonnes	0.019 ton	
Carbon monoxide	14 tons	12 tonnes	0.10 ton	
Water Pollutants				
Saline contamination potential in groundwater				
Solid Wastes				
		Negligible		See oil shale surface retorting
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Mined and primary crushed oil shale rock	24.2×10^6 tons	22.0×10^6 tonnes	178.45×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MODIFIED IN SITU SHALE RETORTING

REFERENCE ENERGY SYSTEM

A modified in situ oil shale retort is comprised of an underground block of oil shale approximately 15-20% of which has been mined by conventional mining techniques to form a cavity at the bottom of the deposit. The material above the cavity is fractured or rubblized after injection and production wells have been drilled on opposing sides of the formation. The rubblized material is ignited to supply heat to the retort and a retorting fluid (hot steam or gas) is passed through the material. Oil mist and liquid is forced up the production well to the surface for further processing.

FACILITY OPERATING PARAMETERS

Size:	102.6×10^3 tons of shale/day retorted in situ 50×10^3 bbl/day of shale produced
Annual Capacity Factor:	90%
Annual Energy Production:	95.3×10^{12} Btu
Efficiency:	61% (thermal overall)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw shale retorted in situ	33.7×10^6 tons	30.6×10^6 tonnes	353.8×10^3 tons	
Raw shale mined and placed above ground	11.2×10^6 tons	10.2×10^6 tonnes	117.9×10^3 tons	
Energy				
		Not Determined		
Water				
Retorting and upgrading	2.12×10^3 acre-ft	2.61×10^9 l	22.2 acre-ft	
Power generation	2.32×10^3 acre-ft	2.87×10^9 l	24.4 acre-ft	
Revegetation	0.09×10^3 acre-ft	0.1×10^9 l	0.9 acre-ft	
Steam injection	2.75×10^3 acre-ft	3.40×10^9 l	28.9 acre-ft	
Miscellaneous	0.42×10^3 acre-ft	0.52×10^9 l	4.4 acre-ft	
Total	7.70×10^3 acre-ft	9.50×10^9 l	80.8 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land	1.41×10^3 - 1.52×10^3 acres	571-617 ha	14.8-16.0 acres	
Personnel				
Construction	2.92×10^3 workers		30.6 workers	
Operation and maintenance		Not Determined		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$\$1.28 \times 10^9$ total	$\$13.4 \times 10^6$ total	
Operation and maintenance	Not Determined		
Environmental Controls			
	Not Determined		

MODIFIED IN SITU SHALE RETORTING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	3.77×10^3 tons	3.42×10^3 tonnes	39.6 tons	
Oxides of nitrogen	3.21×10^3 tons	2.92×10^3 tonnes	33.7 tons	
Oxides of sulfur	591 tons	536 tonnes	6.21 tons	
Carbon dioxide	953 tons	865 tonnes	10.0 tons	
Hydrocarbons	49 tons	44 tonnes	0.51 ton	
Water Pollutants				
Zero discharge to surface water assumed; however, possibility of underground aquifer contamination exists				
Solid Wastes				
Spent shale	9.43×10^6 tons	8.56×10^6 tonnes	99.0×10^3 tons	Aboveground retorting
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Refined shale oil	16.4×10^6 bbl	2.61×10^9 l	172.4×10^3 bbl	
Byproducts				
		Not Determined		
Recoverables/Recyclables				
Water		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

OIL SHALE SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE)

REFERENCE ENERGY SYSTEM

Mine-mouth plant located in the rich oil shale Green River formation, wetting agents, baffled settling chambers, Venturi scrubbers, and baghouse filters for particulate control; Phosam-W process for ammonia removal (nitrogen oxide control); Stretford process for hydrogen sulfide removal (sulfur dioxide control); onsite solid waste disposal; onsite water treatment for recirculation to minimize discharge and external water requirements; and onsite shale oil upgrading facility. Oil shale facilities are subject to future regulations.

FACILITY OPERATING PARAMETERS

Size:	50 × 10^3 bbl/day (syncrude equivalent)
Annual Capacity Factor:	90% (assumed)
Annual Energy Production:	106.4 × 10^{12} Btu
Efficiency:	95% (extraction)
Lifetime:	25 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Run-of-mine oil shale	29.0 × 10^6 tons	26.4 × 10^6 tonnes	273 × 10^3 tons	
Energy				
Diesel fuel for onsite equipment	5.16 × 10^6 gal	19.5 × 10^6 l	48.6 × 10^3 gal	
Processing Materials				
Ammonium nitrate fuel oil (for rubblization)	7.8 × 10^3 tons	7.1 × 10^3 tonnes	73 tons	
Water				
Makeup water	36.3 × 10^3 acre-ft	44.7 × 10^9 l	343 acre-ft	
	Total Usage			
Construction Materials				
	Not Determined			
Land	6.97 × 10^3 acres	2.82 × 10^3 ha	65.5 acres	
Personnel				
Construction (25 yr)	2.3 × 10^3 workers		22 workers	
Operation and maintenance	1.25 × 10^3 workers		11.8 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction (25 yr)	Not Determined		
Operation and maintenance	↓		
Environmental Controls			
	Not Determined		

OIL SHALE SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE)

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	66 tons	60 tonnes	0.62 ton	
Oxides of nitrogen	1.1×10^3 tons	1×10^3 tonnes	10.3 tons	
Total suspended particulates	56 tons	51 tonnes	0.53 ton	
Nonmethane hydrocarbons	66 tons	60 tonnes	0.62 ton	
Carbon monoxide	394 tons	358 tonnes	3.7 tons	
Particulate from crushing	296 tons	269 tonnes	2.8 tons	
Dust from shale storage		Not Determined		
Particulates from retort	460 tons	418 tonnes	4.3 tons	
Carbon dioxide from retort	4.1×10^6 tons	3.7×10^6 tonnes	38.5×10^3 tons	
Post-control flue gas constituents				
• Sulfur dioxide	2.9×10^3 tons	2.6×10^3 tonnes	27.2 tons	0.28 lb/10^6 Btu*
• Oxides of nitrogen	2.1×10^3 tons	1.9×10^3 tonnes	19.7 tons	0.2 lb/10^6 Btu*
• Hydrocarbons	0.1×10^3 tons	0.09×10^3 tonnes	0.94 ton	
• Carbon monoxide	1.8×10^3 tons	1.6×10^3 tonnes	16.9 tons	
• Carbon dioxide	1.1×10^6 tons	1.0×10^6 tonnes	10.3×10^3 tons	
Water Pollutants				
Runoff from shale storage		Negligible		
Runoff from retorted shale	350 acre-ft	433×10^6 l	3.26 acre-ft	
Airborne water from cooling tower drift and evaporation	1.37×10^3 acre-ft	1.68×10^9 l	12.8 acre-ft	
Total suspended solids		Not Determined		25-400 mg/l**
Biological oxygen demand		↓		30 mg/l**
Oil and grease				10-50 mg/l**
Solid Wastes				
Retorted shale	23×10^6 tons	20.9×10^6 tonnes	216×10^3 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

*Regulatory compliance level.

**Colorado water quality standards.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Syncrude	16.4×10^6 bbl	2.6×10^9 l	154×10^3 bbl	
Byproducts				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

	Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths*	1.2	0.012	
Injuries*	69.4	0.65	

*Sum of underground mining and surface retorting.

LURGI PROCESS -- WESTERN SUBBITUMINOUS COAL

(To be provided)

LURGI PROCESS -- WESTERN SUBBITUMINOUS COAL

(To be provided)

TOSCO II SHALE RETORTING

REFERENCE ENERGY SYSTEM

Heated ceramic balls are fed into a horizontal rotating cylindrical retort and mixed with crushed shale (1/2-in. diameter). Pyrolysis occurs at 900°F. Shale oil, steam, and gases are emitted from one end of the retort and are collected and fed into a fractionator for product recovery. The ceramic balls are recycled to a vertical ball heater where reheating for further use occurs.

FACILITY OPERATING PARAMETERS

Size:	50×10^3 bbl/day
Annual Capacity Factor:	90% (328.5 days/yr)
Annual Energy Production:	92.0×10^{12} Btu/yr* (16.4×10^6 bbl/yr)
Efficiency:	67% (thermal)
Lifetime:	30 yr

*At 5.6×10^6 Btu/bbl

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw shale	21.2×10^6 tons	19.2×10^6 tonnes	230×10^3 tons	Oil content is 35 gal/ton
Energy				
		Not Determined		
Processing Materials				
		Not Determined		
Water				
Cooling towers	1.45×10^3 acre-ft	1.79×10^9 l	15.8 acre-ft	
Waste heat boilers	1.33×10^3 acre-ft	1.65×10^9 l	14.5 acre-ft	
Water treatment plant	0.037×10^3 acre-ft	0.046×10^9 l	0.4 acre-ft	
Processed shale	1.96×10^3 acre-ft	2.42×10^9 l	21.3 acre-ft	
Dust control on shale ash	0.36×10^3 acre-ft	0.44×10^9 l	3.9 acre-ft	
Moisture evaporator	0.73×10^3 acre-ft	0.90×10^9 l	7.9 acre-ft	
Dust scrubbers	0.957×10^3 acre-ft	1.18×10^9 l	10.4 acre-ft	
Revegetation	0.10×10^3 acre-ft	0.12×10^9 l	1.1 acre-ft	
Fire and drinking	0.22×10^3 acre-ft	0.27×10^9 l	2.4 acre-ft	
Total	7.14×10^3 acre-ft	8.82×10^9 l	77.7 acre-ft	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	396×10^6 total	4.30×10^6 total	
Operation and maintenance	Not Determined		

TOSCO II SHALE RETORTING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants[a,b]				
Particulates	1.80×10^3 - 2.07×10^3 tons	1.63×10^3 - 1.88×10^3 tonnes	19.6-22.5 tons	
Sulfur dioxide	1.05×10^3 - 1.24×10^3 tons	0.952×10^3 - 1.12×10^3 tonnes	11.4-13.5 tons	
Oxides of nitrogen	5.82×10^3 - 6.87×10^3 tons	5.28×10^3 - 6.23×10^3 tonnes	63.3-74.7 tons	
Hydrocarbons	1.03×10^3 - 1.20×10^3 tons	0.934×10^3 - 1.09×10^3 tonnes	11.2-13.0 tons	
Carbon monoxide	248-273 tons	225-248 tonnes	2.70-2.98 tons	
Water Pollutants				
No direct discharge to any water course				
Solid Wastes				
Spent shale	17.5×10^6 tons	15.9×10^6 tonnes	190×10^3 tons	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Refined shale oil	16.4×10^6 bbl	2.61×10^9 l	179×10^3 bbl	
Byproducts				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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[a] MITRE Corporation and Aerospace Corporation, Technology Characterizations: Environmental Information Handbook, DOE/EV-0072, U.S. Department of Energy, June 1980, p. 147.

[b] Aerospace Corporation, Energy Technologies and the Environment: Environmental Information Handbook (Prepublication Draft), DOE/EV/740101-1, U.S. Department of Energy, December 6, 1980, p. 8-11.

SOLVENT REFINED COAL II

REFERENCE ENERGY SYSTEM

In this plant configuration based on a commercial conceptual design, pulverized, dried coal is slurried with a process-derived oil. After the addition of hydrogen, the pressurized coal/oil/hydrogen mixture is preheated and then pumped into the reactor (2000 psi, 850°F) for the actual liquefaction reaction. The reactor effluent is let down seperating the gaseous products from the slurry. The product gases are cleaned, recycled (hydrogen, which is produced in the process), or burned (fuel gas) for in-plant power/heat. Some liquid product is recycled; the rest is seperated from the heavy bottom slurry by distillation. The heavy bottom is gasified for hydrogen production.

FACILITY OPERATING PARAMETERS

Size:	518 × 10^9 Btu/day total product output (31.6 × 10^3 tons/day coal input)
Annual Capacity Factor:	90%
Annual Energy Production:	170 × 10^{12} Btu
Efficiency:	64% (includes byproducts)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Run-of-mine eastern bituminous coal (7% ash, 3.4% sulfur)	10.4 × 10^6 tons	9.43 × 10^6 tonnes	61.0 × 10^3 tons	
Energy		Not Determined		
Processing Materials				
Hydrogen		Not Determined		
Water	25.2 × 10^3 acre-ft	31.1 × 10^9 l	148 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land	357 acres	145 ha	2.1 acres	Land for disposal not determined
Personnel				
Construction		Not Determined		
Operation and maintenance	969 workers		5.7 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility	(1975 $)		
Construction	$1.53 × 10^9 total	$9.00 × 10^6 total	
Operation and maintenance	$326 × 10^6/yr	$1.92 × 10^6/yr	
Environmental Controls	Not Determined		

SOLVENT REFINED COAL II

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	272 tons	247 tonnes	1.60 tons	
Sulfur dioxide	3.74×10^{3} tons	3.39×10^{3} tonnes	22.0 tons	
Oxides of nitrogen	5.12×10^{3} tons	4.64×10^{3} tonnes	30.1 tons	
Hydrocarbons	663 tons	601 tonnes	3.90 tons	
Carbon monoxide	272 tons	247 tonnes	1.60 tons	
Arsenic	0.306×10^{-3} ton	0.278×10^{-3} tonne	1.80×10^{-6} ton	
Cadmium	28.9×10^{-3} ton	26.2×10^{-3} tonne	0.170×10^{-3} ton	
Mercury	4.93×10^{-3} ton	4.47×10^{-3} tonne	29.0×10^{-6} ton	
Zinc	0.221 ton	0.200 tonne	1.30×10^{-3} ton	
Chromium	0.459 ton	0.416 tonne	2.70×10^{-3} ton	
Nickel	0.100 ton	91.0×10^{-3} tonne	0.590×10^{-3} ton	
Lead	0.105 ton	95.6×10^{-3} tonne	0.620×10^{-3} ton	
Polynuclear organics	0.255×10^{-6} ton	0.231×10^{-6} tonne	1.50×10^{-9} ton	
Water Pollutants				
No direct discharge				
Solid Wastes				
Dry ton equivalent	1.11×10^{6} tons	1.01×10^{6} tonnes	6.55×10^{3} tons	
Thermal Discharge				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Solvent refined coal fuel oil	14.2×10^{6} bbl	2.26×10^{9} l	83.5×10^{3} bbl	
Fuel oil	5.45×10^{6} bbl	866×10^{6} l	32.1×10^{3} bbl	
Naphtha	1.33×10^{6} bbl	211×10^{6} l	7.82×10^{3} bbl	
Byproducts				
Sulfur	0.160×10^{6} tons	0.145×10^{6} tonnes	941 tons	
Ammonia	23.0×10^{3} tons	20.9×10^{3} tonnes	135 tons	
Phenols	12.2×10^{3} tons	11.0×10^{3} tonnes	71.8 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

INDIRECT LIQUEFACTION, LURGI FISCHER-TROPSCH PROCESS

REFERENCE ENERGY SYSTEM

The reference system conceptual design is assumed to be a mine-mouth plant located in Wyoming, using low-sulfur subbituminous coal. The facility includes a utility power plant to provide steam, air separation plant to provide oxygen, and Lurgi dry ash gasifier and Fischer-Tropsch (FT) synthesis are utilized. Environmental controls include electrostatic precipitators for particulate control, sulfur dioxide scrubbers for sulfur dioxide control, Stretford process for sulfur recovery, Lurgi Rectisol process for hydrogen sulfide removal, Lurgi Phenosolvan process for phenol removal, and Chemie Linz/Lurgi process for ammonia recovery. Onsite solid waste disposal and onsite water treatment for recirculation to minimize discharge are assumed.

FACILITY OPERATING PARAMETERS

Size:	45 × 10^3 bbl/day fuel oil equivalent (6 × 10^6 Btu/bbl) (for major energy product slate only)
Annual Capacity Factor:	92%
Annual Energy Production:	90.7 × 10^{12} Btu
Efficiency:	57.6% (based on total product and byproduct energy content)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal to gasifier (well sized)	8.40 × 10^6 tons	7.62 × 10^6 tonnes	92.6 × 10^3 tons	
Coal to utility power plant (fines)	1.70 × 10^6 tons	1.54 × 10^6 tonnes	18.7 × 10^3 tons	
Total run-of-mine coal to plant	10.1 × 10^6 tons	9.16 × 10^6 tonnes	111.3 × 10^3 tons	
Processing Materials				
Limestone (sulfur dioxide scrubber)	12.4 × 10^3 tons	11.3 × 10^3 tonnes	137 tons	
Magnetite iron ore (FT catalyst)	27.3 × 10^3 tons	24.8 × 10^3 tonnes	301 tons	
Water	9.82 × 10^3 acre-ft	12.1 × 10^9 l	107 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land				
Coal mine (mine land)	9.0 × 10^3 – 11 × 10^3 acres	3.6 × 10^3 – 4.4 × 10^3 ha	99–121 acres	
Plant site	630 acres	255 ha	6.94 acres	
Solid waste disposal (estimated)	253 acres	102 ha	2.80 acres	
Personnel				
Construction (5 yr)		Not Determined		
Operation and maintenance				
• Coal mine	400 workers		4.4 workers	
• Liquefaction plant	646 workers		7.1 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	Not Determined		
Operation and maintenance	↓		
Environmental Controls			
	Not Determined		

INDIRECT LIQUEFACTION, LURGI FISCHER-TROPSCH PROCESS

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	3.9 × 10^3 tons	3.6 × 10^3 tonnes	43 tons	
Oxides of nitrogen	8.55 × 10^3 tons	7.8 × 10^3 tonnes	94.0 tons	
Total suspended particulates	0.26 × 10^3 tons	0.24 × 10^3 tonnes	2.9 tons	
Nonmethane hydrocarbons	1.3 × 10^3 tons	1.2 × 10^3 tonnes	14 tons	
Carbon monoxide	2.76 × 10^3 tons	2.5 × 10^3 tonnes	30.4 tons	
Carbon dioxide	11.0 × 10^6 tons	10 × 10^6 tonnes	121 × 10^3 tons	
Arsenic	36.8–90.0 lb	16.7–40.9 kg	0.40–1.0 lb	
Beryllium	4.4–5.7 lb	2.0–2.6 kg	0.049–0.063 lb	
Cadmium	13.2–33.9 lb	6.0–15.4 kg	0.14–0.37 lb	
Manganese	19.9–24.1 lb	9.0–10.9 kg	0.22–0.27 lb	
Lead	14.9–349 lb	6.8–158 kg	0.164–3.85 lb	
Selenium	11.3 lb	5.1 kg	0.12 lb	
Uranium	14.4 lb	6.5 kg	0.16 kg	
Zinc	64.5 lb	29.2 kg	0.71 lb	
Radium-226	0.73 × 10^{-3} Ci	0.73 × 10^{-3} Ci	0.008 × 10^{-3} Ci	
Airborne water from cooling tower drift and evaporation	614 acre-ft	758 × 10^6 l	6.77 acre-ft	
Contaminated steam in synthetic natural gas drying unit vent gas	9.10 × 10^3 tons	8.28 × 10^3 tonnes	100 tons	
Fugitive dust from coal preparation and storage		Not Quantifiable		
Catalyst regeneration offgases		Not Determined		
Water Pollutants				
Runoff from coal storage		Not Quantifiable		
Water runoff from water treatment ponds		Negligible		
Solid Wastes				
Solid waste from coal preparation	100 × 10^3 tons	91.2 × 10^3 tonnes	1.10 × 10^3 tons	
Bottom ash (dry) from utility boiler	17.1 × 10^3 tons	15.6 × 10^3 tonnes	188 tons	
Fly ash (dry) from precipitator	68.5 × 10^3 tons	62.3 × 10^3 tonnes	755 tons	
Limestone sludge from sulfur dioxide control	23.3 × 10^3 tons	21.2 × 10^3 tonnes	257 tons	
Ash (dry) from gasifier	391 × 10^3 tons	356 × 10^3 tonnes	4.31 × 10^3 tons	
Biosludge from wastewater treatment	42 × 10^3 tons	38 × 10^3 tonnes	460 tons	
Spent catalysts from raw gas shift and Fischer-Tropsch		Not Determined		
Catalyst preparation plant tailings	15 × 10^3 tons	14 × 10^3 tonnes	160 tons	
Spent Fischer-Tropsch synthesis catalyst	9.9 × 10^3 tons	9.0 × 10^3 tonnes	110 tons	
Noise Pollution				
		Not Determined		

(Continued on next page)

INDIRECT LIQUEFACTION, LURGI FISCHER-TROPSCH PROCESS

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Synthetic natural gas	58.2×10^9 scf	1.65×10^9 m^3	642×10^6 scf	
Gasoline	4.6×10^6 bbl	0.73×10^9 l	51×10^3 bbl	
Alcohol	0.67×10^6 bbl	0.11×10^9 l	7.4×10^3 bbl	
Diesel and heavy fuel oil	1.0×10^6 bbl	0.16×10^9 l	11×10^3 bbl	
Propane liquid petroleum gas (LPG)	370×10^3 bbl	58.8×10^6 l	4.08×10^3 bbl	
Butane LPG	49×10^3 bbl	7.8×10^6 l	540 bbl	
Byproducts				
Sulfur	20.5×10^3 tons	18.6×10^3 tonnes	0.22×10^3 tons	
Ammonia	34.2×10^3 tons	31.1×10^3 tonnes	377 tons	
Surplus electrical power (3.3 MWe)	90.1×10^9 Btu	95.0×10^{12} J	1.00×10^9 Btu	
Recoverables/Recyclables				
Recovered energy	16×10^{12} Btu	17×10^{15} J	0.018 Btu	Energy derived from the incineration of process materials, including tar, phenols, and tail gases
Recovered water for recycle	56.5×10^3 acre-ft	69.7×10^9 l	623 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual		Per 10^{12} Btu Energy Produced		Remarks
Deaths	Accidental	Disease	Accidental	Disease	
Coal mining	0.83–1.4	1.7–7.8	9.2×10^{-3}–0.015	0.019–0.086	
Coal liquefaction plant construction and operation	0.36	0.26	4.0×10^{-3}	2.9×10^{-3}	
Injuries					
Coal mining	49–100	Not Determined	0.54–1.1	Not Determined	
Coal liquefaction plant	11	↓	0.12	↓	

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COAL TECHNOLOGIES

COAL-OIL MIXTURE PREPARATION PLANT

REFERENCE ENERGY SYSTEM

The system is composed of a receiving facility for the coarsely ground/beneficiated coal, a storage/surge hopper for this material, a fine crushing facility for the coal, a batch or continuous oil-coal blending system, and a facility to pump the mixture into existing No. 6 fuel oil distribution systems. Emission controls are included for fugitive dust, evaporative losses, and onsite water pollution.

FACILITY OPERATING PARAMETERS

Size:	106.0 × 10^3 bbl/system day (20 × 10^3 tons/system day) (mixture 40% coal – 60% oil)
Annual Capacity Factor:	85%
Annual Energy Production:	203.65 × 10^{12} Btu
Efficiency:	99.8% based on $\frac{\text{energy in feed materials}}{\text{energy in mixture + operating energy}}$
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal (coarsely ground)	2.60 × 10^6 tons	2.36 × 10^6 tonnes	12.8 × 10^3 tons	13.06 × 10^3 Btu/lb, 2% sulfur
Oil (No. 6 fuel oil)	23.0 × 10^6 bbl	3.65 × 10^9 l	113 × 10^3 bbl	18.8 × 10^3 Btu/lb, 1% sulfur
Energy				
Operating energy (electricity)	92 × 10^6 kWh	92 × 10^6 kWh	0.45 × 10^6 kWh	
Processing Materials		Not Determined		
Water				
Consumptive uses		Negligible		
	Total Usage			
Construction Materials		Not Determined		
Land	261 acres	106 ha	1.28 acres	
Personnel				
Construction	300 workers		1.47 workers	
Operation and maintenance	120 workers		0.589 worker	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	\$120 × 10^6 total	\$0.589 × 10^6 total	
Operation and maintenance	\$17 × 10^6/yr	\$0.08 × 10^6/yr	
Environmental Controls			
	Not Determined		

COAL-OIL MIXTURE PREPARATION PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Fugitive dust		Not Determined		
Hydrocarbons		↓		
Water Pollutants				
		Not Determined		
Solid Wastes				
		Negligible		
Thermal Discharge				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal-oil mixture (delivered to distribution system)	6.2×10^6 tons (31.9×10^6 bbl)	5.6×10^6 tonnes (5.07×10^9 l)	30×10^3 tons (157×10^3 bbl)	
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BEST DOCUMENT AVAILABLE

COAL-OIL MIXTURE RETROFIT BOILER

REFERENCE ENERGY SYSTEM

The system is comprised of a conventional oil burning steam electric generating plant that has been modified to accept a 40/60 mixture (by weight) of coal and oil as a fuel source. The conversion will involve modification of fuel handling and storage facilities, soot blowing systems, and environmental control systems for air emissions.

FACILITY OPERATING PARAMETERS

Size:	300 MWe
Annual Capacity Factor:	55%
Annual Energy Production:	5.23×10^{12} Btu
Efficiency:	35%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal-oil mixture	2.4×10^6 bbl	380×10^6 l	0.46×10^6 bbl	16.504×10^3 Btu/lb, 9.2 lb/gal
Energy				
Sulfur oxide scrubber operation	200×10^9 Btu	211×10^{12} J	38.2×10^9 Btu	
Electrostatic precipitator	15×10^9 Btu	16×10^{12} J	2.9×10^9 Btu	
Nitrogen oxide control	30×10^9 Btu	32×10^{12} J	5.7×10^9 Btu	
Processing Materials				
		Not Determined		
Water				
Consumptive uses	1.36×10^3 acre-ft	1.67×10^9 l	260 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land				
		Not Determined		Requirements are site specific
Personnel				
Construction		Not Determined		
Operation and maintenance	81.0 workers		15.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction	$0.34 × 10^6 total	$0.066 × 10^6 total	
Operation and maintenance	$4.50 × 10^6/yr	$0.860 × 10^6/yr	
Environmental Controls			
Baghouse	Not Determined		

COAL-OIL MIXTURE RETROFIT BOILER

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur oxides	6.78×10^3 tons	6.16×10^3 tonnes	1.297×10^3 tons	1.297×10^3 tons*
Nitrogen oxides	3.39×10^3 tons	3.08×10^3 tonnes	648 tons	648 tons*
Particulates	753 tons	684 tonnes	144 tons	144 tons*
Carbon monoxide	210 tons	190 tonnes	40 tons	
Hydrocarbons	94 tons	85 tonnes	18 tons	
Water Pollutants				
		Not Determined		
Solid Wastes				
Fly ash	14×10^3 tons	13×10^3 tonnes	2.7×10^3 tons	Assumes 10% ash in coal
Bottom ash	4×10^3 tons	3×10^3 tonnes	0.7×10^3 tons	
Thermal Discharge				
		Not Determined		

*Regulatory compliance level.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity (300 MWe)	1.53×10^9 kWh	1.53×10^9 kWh	0.293×10^9 kWh	
Byproducts				
		Not Determined		
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ATMOSPHERIC FLUIDIZED BED COMBUSTION – BITUMINOUS COAL

REFERENCE ENERGY SYSTEM

Steam electric power generation facility utilizing a fluidized bed combustion system in which the small pieces of coal are suspended along with similarly sized bed material in a continuously moving mass of air. The bed material referred to as a sorbent and composed of crushed limestone or dolomite is responsible for the capture of a portion of the sulfur dioxide generated during combustion. Other environmental control systems include either a baghouse or electrostatic precipitator and conventional water treatment as necessary. The lower combustion temperatures of the system also serve to minimize nitrogen oxide formation.

FACILITY OPERATING PARAMETERS

Size:	814 MWe (4.6 × 10^9 kWh/yr)
Annual Capacity Factor:	65%
Annual Energy Production:	15.8 × 10^{12} Btu
Efficiency:	35.8%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal (bituminous Illinois No. 6)	2.05 × 10^6 tons	1.86 × 10^6 tonnes	129.5 × 10^3 tons	10.78 × 10^3 Btu/lb
Processing Materials				
Limestone (sorbent bed material)	526 × 10^3 tons	478 × 10^3 tonnes	33.3 × 10^3 tons	
Water				
Consumptive uses	2.84 × 10^3 acre-ft	3.51 × 10^9 l	180 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land	246 acres	100 ha	15.6 acres	
Personnel				
Approximately same value as conventional power station of equivalent capacity				

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction	$517 × 10^6 total	$32.7 × 10^6 total	
Operation and maintenance	$54.2 × 10^6/yr	$3.43 × 10^6/yr	
Environmental Controls			
	Not Determined		

ATMOSPHERIC FLUIDIZED BED COMBUSTION—BITUMINOUS COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	22.8×10^3 tons	20.6×10^3 tonnes	1.44×10^3 tons	
Oxides of nitrogen	5.78×10^3 tons	5.25×10^3 tonnes	366 tons	
Particulates	2.18×10^3 tons	1.98×10^3 tonnes	138 tons	
Hydrocarbons	240 tons	220 tonnes	15 tons	
Carbon monoxide	880 tons	800 tonnes	56 tons	
Water Pollutants				
Same values as conventional power station of equivalent capacity				
Solid Wastes	676×10^3 tons	614×10^3 tonnes	42.8×10^3 tons	
Thermal Discharge				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	4.63×10^9 kWh	4.63×10^9 kWh	0.293×10^9 kWh	
Byproducts				
		Not Determined		
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ATMOSPHERIC FLUIDIZED BED COMBUSTION – WESTERN SUBBITUMINOUS COAL

REFERENCE ENERGY SYSTEM

Steam electric power generation facility utilizing a fluidized bed combustion system in which the small pieces of coal are suspended along with similarly sized bed material in a continuously moving mass of air. The bed material referred to as a sorbent and composed of crushed limestone or dolomite is responsible for the capture of a portion of the sulfur dioxide generated during combustion. Other environmental control systems include a baghouse filter with greater than 98% efficiency and conventional water treatment facilities as necessary. The lower combustion temperatures of the system also serve to minimize nitrogen oxide formation.

FACILITY OPERATING PARAMETERS

Size:	536 MWe
Annual Capacity Factor:	95%
Annual Energy Production:	15.2 × 10^{12} Btu
Efficiency:	34.4%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal (subbituminous western)	2.75 × 10^6 tons	2.50 × 10^6 tonnes	181 × 10^3 tons	8.05 × 10^3 Btu/lb
Processing Materials				
Limestone (sorbent bed material)	194 × 10^3 tons	177 × 10^3 tonnes	12.8 × 10^3 tons	
Water				
Consumptive uses	8.86 × 10^3 acre-ft	10.9 × 10^9 l	583 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land	442 acres	179 ha	29.1 acres	
Personnel				
Approximately same as conventional power station of equivalent capacity				

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1977 $)		
Construction	$278 × 10^6 total	$18.3 × 10^6 total	
Operation and maintenance	$5.41 × 10^6/yr	$0.356 × 10^6/yr	
Environmental Controls			
	Not Determined		

ATMOSPHERIC FLUIDIZED BED COMBUSTION — WESTERN SUBBITUMINOUS COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants				
Sulfur dioxide	26×10^3 tons	23×10^3 tonnes	1.7×10^3 tons	
Oxides of nitrogen	8.85×10^3 tons	8.03×10^3 tonnes	582 tons	
Particulates	2.22×10^3 tons	2.01×10^3 tonnes	146 tons	
Hydrocarbons Carbon monoxide	Approximately same values as conventional power station of equivalent capacity			
Water Pollutants				
Approximately same values as conventional power station of equivalent capacity				
Solid Wastes				
Dry weight	384×10^3 tons	349×10^3 tonnes	25.3×10^3 tons	
Thermal Discharge				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Electricity	4.45×10^9 kWh	4.45×10^9 kWh	0.293×10^9 kWh	
Byproducts				
		Not Determined		
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

EASTERN COAL UNIT TRAIN

REFERENCE ENERGY SYSTEM

Typical eastern unit train systems are comprised of 105 cars holding 100 tons each, using four diesel locomotives of 3000 hp each. The train operates between two fixed locations on a dedicated basis. This example assumes a train traveling 700 mi one way and making 90 trips per year. Ten spare cars are reserved for each train system.

FACILITY OPERATING PARAMETERS

Size:	105 cars, 100 tons per car, 10.5×10^{3} tons per train (transported)
Annual Capacity Factor:	Not determined
Annual Energy Production:	24.3×10^{12} Btu (coal transported)
Efficiency:	98.26% based on $\frac{\text{energy delivered}}{\text{energy loaded + energy expanded}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal transported	945×10^{3} tons	858×10^{3} tonnes	38.9×10^{3} tons	
Energy				
Diesel	230×10^{9} Btu	240×10^{12} J	9.5×10^{9} Btu	
	Total Usage			
Construction Materials				
Aluminum	45.4 tons	41.2 tonnes	1.87 tons	
Brass and bronze casting	18 tons	16 tonnes	0.75 ton	
Chromium	2.4 tons	2.2 tonnes	0.10 ton	
Copper	62.7 tons	56.9 tonnes	2.58 tons	
Iron		Not Determined		
Manganese	32.3 tons	29.3 tonnes	1.33 tons	
Nickel	0.5 ton	0.4 tonne	0.02 ton	
Steel	4.50×10^{3} tons	4.08×10^{3} tonnes	185.0 tons	
Land				
Land value has been excluded as it cannot be exclusively associated with coal transportation				
Personnel				
Construction		Not Determined		
Operation and maintenance	125 workers		5.16 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	$\$8.09 \times 10^{6}$ total	$\$0.333 \times 10^{6}$ total	
Operation and maintenance	$\$7.22 \times 10^{6}$/yr	$\$0.297 \times 10^{6}$/yr	

EASTERN COAL UNIT TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants				
Particulates	2.50×10^3 tons	2.27×10^3 tonnes	102.9 tons	
Sulfur dioxide	90 tons	82 tonnes	3.7 tons	
Oxides of nitrogen	78 tons	71 tonnes	3.2 tons	
Hydrocarbons	61 tons	55 tonnes	2.5 tons	
Carbon monoxide	83 tons	75 tonnes	3.4 tons	
Aldehydes	14 tons	13 tonnes	0.6 ton	
Noise Pollution*				
In-cab noise level		>112 dBA		Federal design levels: 55 dBA—residence 75 dBA—open land
100 ft from moving train		~95 dBA		
1000 ft from moving train		~75 dBA		
Whistle noise at 1000 ft		≤85 dBA		

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Coal transported	945×10^3 tons	858×10^3 tonnes	38.9×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

WESTERN COAL UNIT TRAIN

REFERENCE ENERGY SYSTEM

Typical western unit train systems are comprised of 100 cars each holding 100 tons and four diesel locomotives of 3000 hp each. The train operates between two fixed locations on a dedicated basis. This example assumes a train traveling 700 mi one way and making 90 trips per year. Ten spare cars are reserved for each train system.

FACILITY OPERATING PARAMETERS

Size:	100 cars, 100 tons per car, 10×10^3 tons per train
Annual Capacity Factor:	Not determined
Annual Energy Production:	17.01×10^{12} Btu (coal transported)
Efficiency:	99.69% based on $\frac{\text{energy delivered}}{\text{energy loaded + energy expended}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Coal transported	900×10^3 tons	817×10^3 tonnes	52.9×10^3 tons	
Energy				
Diesel	221×10^9 Btu	233×10^{12} J	13.0×10^9 Btu	
	Total Usage			
Construction Materials				
Aluminum	43.2 tons	39.2 tonnes	2.54 tons	
Brass and bronze casting	17.4 tons	15.8 tonnes	1.02 tons	
Chromium	2.2 tons	2.0 tonnes	0.13 ton	
Copper	59.7 tons	54.2 tonnes	3.51 tons	
Iron		Not Determined		
Manganese	30.6 tons	27.8 tonnes	1.80 tons	
Nickel	0.51 ton	0.46 tonne	0.03 ton	
Steel	4.27×10^3 tons	3.88×10^3 tonnes	251 tons	
Land				
Land value has been excluded as it cannot be exclusively associated with coal transportation				
Personnel				
Construction		Not Determined		
Operation and maintenance	120 workers		7.02 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$7.70 × 10^6 total	$0.454 × 10^6 total	
Operation and maintenance	$6.87 × 10^6/yr	$0.403 × 10^6/yr	

WESTERN COAL UNIT TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	2.38 × 10^3 tons	2.16 × 10^3 tonnes	140 tons	
Sulfur dioxide	90 tons	80 tonnes	5.0 tons	
Oxides of nitrogen	75 tons	68 tonnes	4.4 tons	
Hydrocarbons	61 tons	56 tonnes	3.6 tons	
Carbon monoxide	78 tons	71 tonnes	4.6 tons	
Aldehydes	14 tons	12 tonnes	0.8 ton	
Noise Pollution*				
In-cab noise level		≥112 dBA		Federal design levels:
100 ft from moving train		~95 dBA		55 dBA — residence
1000 ft from moving train		~75 dBA		75 dBA — open land
Whistle noise at 1000 ft		≤85 dBA		

*Noise cannot be expressd in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported	900 × 10^3 tons	817 × 10^3 tonnes	52.9 × 10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

EASTERN COAL CONVENTIONAL TRAIN

REFERENCE ENERGY SYSTEM

A conventional freight train is assumed to be made up of 85 freight cars, 17 of which carry 85 tons each of coal. The train may have multiple destinations and be made up of a mixture of cars from many sources requiring more than one make-up and breakdown during a single trip. This example assumes a 300-mi one-way trip using a diesel-powered locomotive. The train is assumed to make the equivalent of 20 round trips per year.

FACILITY OPERATING PARAMETERS

Size:	29 × 10^3 tons/yr (transported)
Annual Capacity Factor:	Not determined
Annual Energy Production:	0.745 × 10^{12} Btu (coal transported)
Efficiency:	98.6% based on $\frac{\text{coal delivered}}{\text{coal loaded + energy used}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal transported	29.0 × 10^3 tons	26.4 × 10^3 tonnes	39.0 × 10^3 tons	
Energy				
Diesel fuel	8.05 × 10^9 Btu	8.49 × 10^{12} J	10.8 × 10^9 Btu	
	Total Usage			
Construction Materials				
Aluminum	4.20 tons	3.81 tonnes	5.64 tons	
Brass and bronze	2.48 tons	2.25 tonnes	3.33 tons	
Chromium	0.30 ton	0.27 tonne	0.40 ton	
Copper	7.27 tons	6.60 tonnes	9.76 tons	
Iron		Not Determined		
Manganese	4.48 tons	4.07 tonnes	6.02 tons	
Nickel	0.07 ton	0.06 tonne	0.09 ton	
Steel	629 tons	571 tonnes	844 tons	
Land				
Land use value has been excluded as it cannot be exclusively associated with coal transportation				
Personnel				
Construction		Not Determined		
Operation and maintenance	2.91 workers		3.91 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	\$0.976 × 10^6 total	\$1.31 × 10^6 total	
Operation and maintenance	\$0.637 × 10^6/yr	\$0.855 × 10^6/yr	

EASTERN COAL CONVENTIONAL TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	76.0 tons	69.0 tonnes	102.0 tons	
Sulfur dioxide	1.9 tons	1.8 tonnes	2.6 tons	
Oxides of nitrogen	2.2 tons	2.0 tonnes	2.9 tons	
Hydrocarbons	1.5 tons	1.4 tonnes	2.0 tons	
Carbon monoxide	2.0 tons	1.8 tonnes	2.7 tons	
Aldehydes, etc.	0.4 ton	0.3 tonne	0.5 ton	
Noise Pollution*				
In-cab noise level		>112 dBA		Federal design levels:
100 ft from moving train		~ 95 dBA		55 dBA – residence
1000 ft from moving train		~ 75 dBA		75 dBA – open land
Whistle noise at 1000 ft		≤ 85 dBA		

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported	29.0×10^3 tons	26.3×10^3 tonnes	38.9×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

WESTERN COAL CONVENTIONAL TRAIN

REFERENCE ENERGY SYSTEM

A conventional freight train is assumed to be made up of 85 freight cars, 17 of which carry 85 tons each of coal. The train may have multiple destinations and thus be made up of a mix of cars from many sources requiring more then one make-up and breakdown of the train during a single trip. This example assumes a 300-mi one-way trip using a diesel-powered locomotive. The train is assumed to make the equivalent of 20 round trips per year.

FACILITY OPERATING PARAMETERS

Size:	29×10^3 tons/yr (transported)
Annual Capacity Factor:	Not determined
Annual Energy Production:	0.548×10^{12} Btu (coal transported)
Efficiency:	98.3% based on $\frac{\text{coal delivered}}{\text{coal loaded} + \text{energy consumed}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal transported	29.1×10^3 tons	26.4×10^3 tonnes	53.04×10^3 tons	
Energy				
Diesel fuel	8.06×10^9 Btu	8.50×10^{12} J	14.7×10^9 Btu	
	Total Usage			
Construction Materials				
Aluminum	4.20 tons	3.82 tonnes	7.67 tons	
Brass and bronze	2.48 tons	2.25 tonnes	4.52 tons	
Chromium	0.30 ton	0.27 tonne	0.54 ton	
Copper	7.27 tons	6.60 tonnes	13.27 tons	
Iron		Not Determined		
Manganese	4.48 tons	4.07 tonnes	8.18 tons	
Nickel	0.066 ton	0.060 tonne	0.12 ton	
Steel	6.28 tons	5.71 tonnes	11.47 tons	
Land				
Land use value has been excluded as it cannot be exclusively associated with coal transportation				
Personnel				
Construction		Not Determined		
Operation and maintenance	2.92 workers		5.32 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$0.975 × 10^6 total	$1.78 × 10^6 total	
Operation and maintenance	$0.658 × 10^6/yr	$1.20 × 10^6/yr	

WESTERN COAL CONVENTIONAL TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	75.8 tons	68.8 tonnes	138.4 tons	Includes particulates from locomotives and fugitive emissions
Sulfur dioxide	1.9 tons	1.7 tonnes	3.5 tons	
Oxides of nitrogen	2.2 tons	2.0 tonnes	4.0 tons	
Hydrocarbons	1.5 tons	1.3 tonnes	2.7 tons	
Carbon monoxide	2.0 tons	1.8 tonnes	3.7 tons	
Aldehydes, etc.	0.33 ton	0.30 tonne	0.6 ton	
Noise Pollution*				
In cab of locomotive		>112 dBA		Federal design levels:
100 ft from moving train		~95 dBA		55 dBA – residence
1000 ft from moving train		~75 dBA		75 dBA – open land
Whistle noise at 1000 ft		≤85 dBA		

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported	29.0×10^3 tons	26.3×10^3 tonnes	52.9×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

COAL TRANSPORTATION BY TRUCK—EASTERN COAL

REFERENCE ENERGY SYSTEM

This transport system is assumed to consist of one over-the-road tractor trailer unit capable of carrying 25 tons over a distance of 60 mi round trip. The truck is assumed to operate 240 days/yr on a 10-hr day and make 800 round trips per year or 1.2×10^6 net ton miles.

FACILITY OPERATING PARAMETERS

Size:	20.0×10^3 tons/yr (transported)
Annual Capacity Factor:	27.5% based on $\frac{\text{time-in-use}}{\text{time (24-hr day)}}$
Annual Energy Production:	0.514×10^{12} Btu (coal transported)
Efficiency:	99.9% based on $\frac{\text{coal delivered}}{\text{coal loaded + fuel consumed}}$
Lifetime:	7 yr

RESOURCES USED

	Quantities Used			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Coal transported	20.0×10^3 tons	18.2×10^3 tonnes	38.9×10^3 tons	
Energy				
Diesel fuel	1.61×10^9 Btu	1.70×10^{12} J	3.13×10^9 Btu	
	Total Usage			
Construction Materials				
Carbon steel	11.6 tons	10.5 tonnes	22.6 tons	
Cast iron	0.31 ton	0.30 tonne	0.6 ton	
Structural steel	2.0 tons	1.8 tonnes	3.8 tons	
Steel plate (< 1.5 in. thick)	1.6 tons	1.5 tonnes	3.2 tons	
Personnel				
Construction	Not Determined			
Operation and maintenance	2.5 workers		4.9 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$0.077 × 10^6 total	$0.15 × 10^6 total	
Operation and maintenance	$0.10 × 10^6/yr	$0.19 × 10^6/yr	

COAL TRANSPORTATION BY TRUCK—EASTERN COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Total suspended particulates	18.1 tons	16.4 tonnes	35.16 tons	
Oxides of sulfur	0.15 ton	0.14 tonne	0.29 ton	
Oxides of nitrogen	0.961 ton	0.872 tonne	1.87 tons	
Carbon monoxide	1.52 tons	1.38 tonnes	2.95 tons	
Hydrocarbons	0.24 ton	0.22 tonne	0.47 ton	
Aldehydes	0.02 ton	0.01 tonne	0.03 ton	
Organic acids	0.02 ton	0.01 tonne	0.03 ton	
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported	20.0×10^3 tons	18.2×10^3 tonnes	38.9×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SLURRY PIPELINE

REFERENCE ENERGY SYSTEM

The system is comprised of a 38-in.-diameter pipeline through which a 50-50 mixture (by volume) of coal and water is pumped in a manner similar to crude oil. The system includes a slurry preparation plant, pipeline, pumping facilities, dewatering facilities, and in some instances, a storage facility. The assumed system is transporting western subbituminous coal over 1356 mi.

FACILITY OPERATING PARAMETERS

Size:	25.0 × 10^6 tons/yr
Annual Capacity Factor:	100%
Annual Energy Production:	472.5 × 10^{12} Btu (coal transported)
Efficiency:	94.2% based on $\frac{\text{energy delivered}}{\text{energy loaded} + \text{energy used}}$
Lifetime:	40 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal transported	25.0 × 10^6 tons	22.7 × 10^6 tonnes	52.91 × 10^3 tons	Subbituminous
Energy				
Electricity (pumping energy)	5.7 × 10^9 kWh	5.7 × 10^9 kWh	12 × 10^6 kWh	
Processing Materials				
		Not Determined		
	Total Usage			
Construction Materials				
Aluminum	633 tons	575 tonnes	1.34 tons	
Brass and bronze	190 tons	170 tonnes	0.40 ton	
Chromium	140 tons	130 tonnes	0.30 ton	
Concrete	1.42 × 10^6 tons	1.29 × 10^6 tonnes	3.017 × 10^3 tons	
Copper	2.09 × 10^3 tons	1.90 × 10^3 tonnes	4.43 tons	
Iron		Not Determined		
Manganese	4.54 × 10^3 tons	4.13 × 10^3 tonnes	9.62 tons	
Nickel	14 tons	13 tonnes	0.03 ton	
Steel	608 × 10^3 tons	552 × 10^3 tonnes	1.286 × 10^3 tons	
Water				
Consumptive uses	18.4 × 10^3 acre-ft	22.7 × 10^9 l	38.87 acre-ft	
Land	17.7 × 10^3 acres	71.5 × 10^3 ha	37.4 acres	
Personnel				
Construction	5.81 × 10^3 workers		12.3 workers	
Operation and maintenance	1.07 workers		2.26 × 10^{-3} workers	

SLURRY PIPELINE

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$\$1.18 \times 10^9$ total	$\$2.50 \times 10^6$ total	
Operation and maintenance	$\$85.0 \times 10^6$/yr	$\$0.180 \times 10^6$/yr	
Environmental Controls			
	Not Determined		

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
		Not Determined		
Water Pollutants				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported	25.0×10^6 tons	22.7×10^6 tonnes	52.91×10^3 tons	
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BEST DOCUMENT AVAILABLE

COAL BENEFICIATION

REFERENCE ENERGY SYSTEM

The system is comprised of a number of wet circuit coal benefication devices including crushers, scalping screens, rotary breaker, vibrating screens, jigs, thickeners, concentrating tables, flotation circuits, and thermal drying. These devices are designed to remove unwanted components from the raw coal, such as ash to improve the energy content or sulfur to reduce the sulfur oxide emissions. The resultant cleaned coal can then be utilized in a manner essentially identical to other unprocessed coal that has not undergone this degree of benefication.

FACILITY OPERATING PARAMETERS

Size:	2.857 × 10^6 tons/yr
Annual Capacity Factor:	83% (based on 230 days/yr of operation)
Annual Energy Production:	55.0 × 10^{12} Btu
Efficiency:	87.5%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal (run-of-mine)	2.86 × 10^6 tons	2.59 × 10^6 tonnes	51.945 × 10^3 tons	
Energy				
Electricity	11 × 10^6 kWh	11 × 10^6 kWh	0.20 × 10^6 kWh	
Oil	32 × 10^9 Btu	34 × 10^{12} J	0.59 × 10^9 Btu	
Processing Materials				
		Not Determined		
Water				
Consumptive uses	200 acre-ft	250 × 10^6 l	3.7 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land	240 acres	96 ha	4.3 acres	
Personnel				
Construction (1 yr)	440 workers		8.1 workers	
Operation and maintenance	82 workers		1.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1976 $)		
Construction (1 yr)	$24 × 10^6 total	$0.43 × 10^6 total	
Operation and maintenance	$18 × 10^6/yr	$0.32 × 10^6/yr	
Environmental Controls			
	Not Determined		

COAL BENEFICIATION

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	50 tons	40 tonnes	0.9 ton	
Sulfur dioxide	0.3 ton	0.2 tonne	0.005 ton	
Oxides of nitrogen	33 tons	30 tonnes	0.6 ton	
Hydrocarbons	11 tons	10 tonnes	0.2 ton	
Carbon monoxide	11 tons	10 tonnes	0.2 ton	
Water Pollutants				
Total dissolved solids	1.82×10^3 tons	1.65×10^3 tonnes	33 tons	
• Iron	0.4 ton	0.3 tonne	0.007 ton	
• Manganese	1.6 tons	1.5 tonnes	0.03 ton	
• Aluminum	2.2 tons	2.0 tonnes	0.4 ton	
• Zinc	0.3 ton	0.2 tonne	0.005 ton	
• Nickel	0.16 ton	0.15 tonne	0.003 ton	
Total suspended solids	33 tons	30 tonnes	0.6 ton	
• Iron	3.3 tons	3.0 tonnes	0.06 ton	
Ammonia	3.0 tons	2.0 tonnes	0.05 ton	
Sulfates	990 tons	900 tonnes	18.0 tons	
Solid Wastes				
Course cleaning	0.11×10^3 tons	0.1×10^3 tonnes	0.002×10^3 tons	
Primary cleaning	559×10^3 tons	508×10^3 tonnes	10.16×10^3 tons	
Froth flotation	290×10^3 tons	260×10^3 tonnes	5.3×10^3 tons	
Breaking and sizing	0.11×10^3 tons	0.1×10^3 tonnes	0.002×10^3 tons	
Total	849×10^3 tons	768×10^3 tonnes	15.5×10^3 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
May affect workers but not nearby receptors				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal (cleaned)	2.00×10^6 tons	1.82×10^6 tonnes	36.4×10^3 tons	
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

COAL-FIRED POWER PLANT – EASTERN COAL

REFERENCE ENERGY SYSTEM

The system is composed of a mine-mouth conventional steam electric power plant using typical eastern bituminous coal with no cogeneration. Environmental control systems include an electrostatic precipitator for particulate control and onsite solid waste disposal. An onsite water and recirculation facility is used to minimize liquid discharges from the plant. The plant is assumed to be subject to the current regulations governing such facilities.

FACILITY OPERATING PARAMETERS

Size:	500 MWe
Annual Capacity Factor:	80%
Annual Energy Production:	12×10^{12} Btu
Efficiency:	35%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Run-of-mine coal	1.96×10^6 tons	1.77×10^6 tonnes	0.16×10^6 tons	
Processing Materials				
Limestone to sulfur dioxide scrubber	146×10^3 tons	132×10^3 tonnes	12.2×10^3 tons	
Water				
Coal preparation – consumption	58-138 acre-ft	71×10^6 - 170×10^6 l	4.8-11.5 acre-ft	
Power plant make-up – consumption	8.3×10^3 acre-ft	10×10^9 l	0.69×10^3 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land				
Coal preparation and associated solid waste disposal	480 acres	194 ha	40 acres	
Power plant and associated solid waste disposal (ash and scrubber sludge)	369 acres	149 ha	30.8 acres	
Personnel				
Construction		Not Determined		
Operation and maintenance	160 workers		13.0 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	Not Determined		
Operation and maintenance	↓		
Environmental Controls			
	Not Determined		

COAL-FIRED POWER PLANT — EASTERN COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	10.2×10^3 tons	9.26×10^3 tonnes	850 tons	0.6 lb/10^6 Btu*
Oxides of nitrogen	10.2×10^3 tons	9.26×10^3 tonnes	850 tons	0.6 lb/10^6 Btu*
Total suspended particulates	500 tons	460 tonnes	42 tons	0.03 lb/10^6 Btu*
Nonmethane hydrocarbons	220 tons	200 tonnes	18 tons	
Carbon monoxide	720 tons	655 tonnes	60 tons	
Carbon dioxide	3.7×10^6 tons	3.4×10^6 tonnes	0.3×10^6 tons	
Arsenic	225 lb	102 kg	18.8 lb	
Beryllium	9.3 lb	4.2 kg	0.8 lb	
Cadmium	4.1 lb	1.9 kg	0.4 lb	
Manganese	161 lb	74 kg	13.4 lb	
Lead	114 lb	52 kg	9.5 lb	
Selenium	56 lb	25 kg	4.7 lb	
Radium	3.0×10^{-3} Ci	3.0×10^{-3} Ci	0.25×10^{-3} Ci	
Water Pollutants				
Excess water discharge characteristics (estimated max.)				
• Total suspended solids	Metric	30 mg/l	Depends	30 mg/l**
• Oil and grease	units	15.2 mg/l	on	
• Copper	are	0.009 mg/l	flow,	1 mg/l**
• Iron	universally	0.009 mg/l	which	1 mg/l**
• Chlorine	used	30.1 mg/l	varies	
Solid Wastes				
Waste from coal preparation	0.5×10^6 tons	0.4×10^6 tonnes	0.04×10^6 tons	
Bottom ash from boiler (dry)	25×10^3 tons	23×10^3 tonnes	2.1×10^3 tons	
Collected fly ash (dry)	100×10^3 tons	90×10^3 tonnes	8.3×10^3 tons	
Limestone scrubber sludge (dry)	193×10^3 tons	175×10^3 tonnes	16×10^3 tons	
Thermal Discharge				
Heat loss to air	34×10^{12} Btu	36×10^{15} J	2.8×10^{12} Btu	

*Regulatory compliance levels.
**State of Kentucky standards.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electric power	12×10^{12} Btu	13×10^{15} J	1.0×10^{12} Btu	
Recoverables/Recyclables				
Water to recycle	89.0 acre-ft	110×10^6 l	7.42 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths			
Preparation plant	0.004–0.005	0.3×10^{-3}–0.4×10^{-3}	
Power plant	0–0.11	0–9.5×10^{-3}	
Injuries			
Preparation plant	1.9–3.1	0.16–0.26	
Power plant	1.9–2.3	0.16–0.19	

COAL-FIRED POWER PLANT — WESTERN COAL

REFERENCE ENERGY SYSTEM

The system is composed of a conventional steam electric power plant using typical western low-sulfur subbituminous coal supplied by a unit train operation. No cogeneration is included. Environmental control systems include electrostatic precipitators for particulate control, wet lime/limestone scrubbers for sulfur dioxide control, onsite solid waste disposal, and onsite water treatment for water recirculation to eliminate liquid discharges. The plant is assumed to be subject to current regulations.

FACILITY OPERATING PARAMETERS

Size:	500 MWe
Annual Capacity Factor:	80%
Annual Energy Production:	12 × 10^{12} Btu
Efficiency:	35%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Run-of-mine subbituminous coal	2.11 × 10^6 tons	1.92 × 10^6 tonnes	0.18 × 10^6 tons	Low-sulfur coal (0.63% sulfur)
Processing Materials				
Limestone to sulfur dioxide scrubber	32 × 10^3 tons	29 × 10^3 tonnes	2.7 × 10^3 tons	
Fly ash (sludge fixing)	100 × 10^3 tons	92 × 10^3 tonnes	8.4 × 10^3 tons	
Water				
Water consumed (generating plant)	4.9 × 10^3 acre-ft	6.1 × 10^9 l	0.41 × 10^3 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land				
Plant and solid waste disposal (ash and scrubber sludge)	156 acres	63.1 ha	12.9 acres	Additional land required for water and coal storage and buffer zone
Personnel				
Construction		Not Determined		
Operation and maintenance	155 workers		13.0 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	Not Determined		
Operation and maintenance	↓		
Environmental Controls			
	Not Determined		

COAL-FIRED POWER PLANT — WESTERN COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants				
Fugitive coal dust (unit train operation)	5.2×10^3 tons	4.7×10^3 tonnes	0.43×10^3 tons	
Sulfur dioxide	7.15×10^3 tons	6.49×10^3 tonnes	0.60×10^3 tons	0.42 lb/10^6 Btu*
Oxides of nitrogen	10.2×10^3 tons	9.26×10^3 tonnes	0.85×10^3 tons	0.6 lb/10^6 Btu*
Total suspended particulates	0.525×10^3 tons	0.48×10^3 tonnes	0.04×10^3 tons	0.03 lb/10^6 Btu*
Nonmethane hydrocarbons	0.32×10^3 tons	0.29×10^3 tonnes	0.03×10^3 tons	
Carbon monoxide	1.05×10^3 tons	0.95×10^3 tonnes	0.09×10^3 tons	
Carbon dioxide	3.7×10^6 tons	3.4×10^6 tonnes	0.31×10^6 tons	
Arsenic	128 lb	58.1 kg	10.7 lb	
Beryllium		Not Determined		
Cadmium	11.7 lb	5.3 kg	0.98 lb	
Manganese	0.6 lb	0.3 kg	0.05 lb	
Lead	32.1 lb	14.6 kg	2.68 lb	
Selenium	2.0 lb	0.9 kg	0.17 lb	
Uranium	718 lb	326 kg	59.8 lb	
Zinc	286 lb	130 kg	23.8 lb	
Radium-226	1.4×10^{-3} Ci	1.4×10^{-3} Ci	0.12×10^{-3} Ci	
Solid Wastes				
Coal preparation (at mine)	210×10^3 tons	190×10^3 tonnes	17.5×10^3 tons	
Boiler bottom ash (dry)	34×10^3 tons	31×10^3 tonnes	2.8×10^3 tons	
Boiler fly ash (dry)	101×10^3 tons	91.7×10^3 tonnes	8.4×10^3 tons	
Sulfur dioxide scrubber sludge (dry)	43×10^3 tons	39×10^3 tonnes	3.6×10^3 tons	
Total solid waste to onsite disposal	177×10^3 tons	161×10^3 tonnes	14.8×10^3 tons	
Thermal Discharge				
		Not Determined		

*Regulatory compliance level.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Electricity	12×10^{12} Btu	13×10^{15} J	1.0×10^{12} Btu	
Byproducts				
Fly ash (for sale)	34×10^3 tons	31×10^3 tonnes	2.9×10^3 tons	
Recoverables/Recyclables				
Water to recycle		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths			
Power plant	0–0.11	$0\text{–}9.5 \times 10^{-3}$	
Injuries			
Power plant	1.9–2.3	0.16–0.19	

SURFACE COAL MINING – EASTERN

REFERENCE ENERGY SYSTEM

The reference energy system consists of a surface mining operation operating in the Eastern United States. The mine is utilizing hilltop removal operations in a general areawide configuration to remove coal from a 6-ft-thick seam. The removal efficiency is 80% with respect to coal in place. The mined coal is assumed to be 3% moisture, 34.1% volatile matter, 52.4% fixed carbon, 9.6% ash, and 2.1% sulfur. Major mining equipment includes draglines, stripping shovels, bulldozers, front-end loaders, and haulage trucks.

FACILITY OPERATING PARAMETERS

Size:	2.5 × 10^6 tons/yr
Annual Capacity Factor:	Not determined
Annual Energy Production:	59.8 × 10^{12} Btu
Efficiency:	80%
Lifetime:	60 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw coal in place				Assumed to be 60-yr or more supply
Energy				
Diesel fuel	239 × 10^9 Btu	253 × 10^{12} J	4 × 10^9 Btu	
Electricity	35.3 × 10^6 kWh	35.3 × 10^6 kWh	0.59 × 10^6 kWh	
Water				
Consumption	102 acre-ft	125 × 10^6 l	1.7 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land				
Fixed	17.9 acres	7.24 ha	0.3 acre	
Incremental	365 acres	148 ha	6.1 acres	
Personnel				
Construction	353 workers		5.9 workers	
Operation and maintenance	257 workers		4.3 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	\$115 × 10^6 total	\$1.92 × 10^6 total	
Operation and maintenance	\$27.5 × 10^6/yr	\$0.46 × 10^6/yr	
Environmental Controls	Not Determined		

SURFACE COAL MINING – EASTERN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Air Pollutants				
Particulates	1.19 tons	1.08 tonnes	0.02 ton	75 $\mu g/m^3$ annual*
Sulfur dioxide	5.98 tons	5.43 tonnes	0.1 ton	80 $\mu g/m^3$ annual*
Oxides of nitrogen	89.7 tons	81.4 tonnes	1.5 ton	100 $\mu g/m^3$ annual*
Hydrocarbons	11.9 tons	10.8 tonnes	0.2 ton	
Carbon monoxide	53.8 tons	48.8 tonnes	0.9 ton	10×10^3 $\mu g/m^3$ annual*
Water Pollutants				
Total dissolved solids	1.24×10^3 tons	1.13×10^3 tonnes	20.8 tons	250 mg/l*
• Iron	0.023 ton	0.021 tonne	0.4×10^{-3} ton	0.3 mg/l*
• Manganese	5.98 tons	5.43 tonnes	0.1 ton	0.050 mg/l*
• Aluminum	1.79 tons	1.62 tonnes	0.03 ton	
• Zinc	0.119 ton	0.108 tonne	0.002 ton	5 mg/l*
• Nickel	0.119 ton	0.108 tonne	0.002 ton	0.046 mg/l*
Total suspended solids	23.9 tons	21.7 tonnes	0.4 ton	
• Iron	0.239 ton	0.217 tonne	0.004 ton	
Ammonia	1.19 tons	1.08 tonnes	0.02 ton	0.02 mg/l*
Sulfate	855 tons	776 tonnes	14.3 tons	250 mg/l*
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

*Regulatory compliance level.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Primary				
Coal	2.5×10^6 tons	2.3×10^6 tonnes	42×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SURFACE COAL MINING – WESTERN

REFERENCE ENERGY SYSTEM

The reference energy system consists of a surface mining operation in the Western United States. The mine is utilizing area strip mining techniques and configurations to remove coal from a 25- to 30-ft thick seam, with a removal efficiency of 89% based on total coal in place. The coal is assumed to have 21.5% moisture, 34 to 35% volatile matter, 39.6% fixed carbon, 4.4% ash, and 0.4% sulfur by weight. Major equipment involved in the mining operation includes draglines, coal shovels, bulldozers, front end loaders, scrapers, and trucks.

FACILITY OPERATING PARAMETERS

Size:	6×10^6 tons/yr
Annual Capacity Factor:	Not determined
Annual Energy Production:	110×10^{12} Btu (equivalent)
Efficiency:	89%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw coal in place				Assumed to be 30-yr or more supply
Energy				
Fuel	860×10^9 Btu	930×10^{12} J	8×10^9 Btu	
Electricity	12×10^6 kWh	12×10^6 kWh	0.11×10^6 kWh	
Water				
Consumption	300 acre-ft	400×10^6 l	3 acre-ft	
	Total Usage			
Land				
Fixed	40 acres	20 ha	0.4 acre	
Incremental	200 acres	80 ha	1.8 acres	
Personnel				
Construction	380 workers		3.5 workers	
Operation and maintenance	380 workers		3.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1977 $)		
Construction	170×10^6 total	1.55×10^6 total	
Operation and maintenance	31×10^6/yr	0.28×10^6/yr	
Environmental Controls			
	Not Determined		

SURFACE COAL MINING – WESTERN

ENVIRONMENTAL RESIDUALS

	Quantities Released Reference Energy System Annual Levels English Units	Quantities Released Reference Energy System Annual Levels Metric Units	Quantities Released Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	9 tons	8 tonnes	0.08 ton	75 $\mu g/m^3$ annual*
Sulfur dioxide	22 tons	20 tonnes	0.2 ton	80 $\mu g/m^3$ annual*
Oxides of nitrogen	220 tons	200 tonnes	2.0 tons	100 $\mu g/m^3$ annual*
Hydrocarbons	22 tons	20 tonnes	0.2 ton	
Carbon monoxide	130 tons	120 tonnes	1.2 tons	10 × 10^3 $\mu g/m^3$ annual*
Water Pollutants				
Total dissolved solids	2.63 × 10^3 tons	2.39 × 10^3 tonnes	23.9 tons	250 mg/l*
• Iron	0.6 ton	0.5 tonne	0.005 ton	0.3 mg/l*
• Manganese	2.2 tons	2.0 tonnes	0.02 ton	0.050 mg/l*
• Aluminum	0.7 ton	0.6 tonne	0.006 ton	
• Zinc	0.6 ton	0.5 tonne	0.005 ton	5 mg/l*
• Nickel	0.11 ton	0.10 tonne	0.001 ton	0.046 mg/l*
Total suspended solids	250 tons	230 tonnes	2.3 tons	
• Iron	2.2 tons	2.0 tonnes	0.02 ton	
Ammonia	22 tons	20 tonnes	0.2 ton	0.02 mg/l*
Sulfate	3.60 × 10^3 tons	3.27 × 10^3 tonnes	32.7 tons	250 mg/l*
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

*Regulatory compliance level.

PRODUCTS

	Quantities Produced Reference Energy System Annual Production English Units	Quantities Produced Reference Energy System Annual Production Metric Units	Quantities Produced Per 10^{12} Btu Energy Produced	Remarks
Primary				
Run-of-mine coal	6.00 × 10^6 tons	5.45 × 10^6 tonnes	54.5 × 10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

UNDERGROUND COAL MINING – EASTERN

REFERENCE ENERGY SYSTEM

The reference energy system consists of an underground coal mine operating in the Eastern United States utilizing a room and pillar mining scheme. The mine is assumed to be extracting coal from a 50 in. seam using continuous mining equipment. The coal is assumed to be 3.9% moisture, 34.1% volatile matter, 52.4% fixed carbon, 9.6% ash, and 2.1% sulfur by weight. Major equipment includes in-mine conveyors, roof bolting machines, loading machines, shuttle cars, and rock dusting machines.

FACILITY OPERATING PARAMETERS

Size:	2×10^6 tons/yr
Annual Capacity Factor:	Not determined
Annual Energy Production:	51.4×10^{12} Btu
Efficiency:	57%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Raw coal in place				Assumed to be 20-yr or more supply
Energy				
Electricity	37.0×10^6 kWh	37.0×10^6 kWh	0.72×10^6 kWh	
Water				
Consumption	118 acre-ft	146×10^6 l	2.3 acre-ft	
	Total Usage			
Land				
Fixed	15.4 acres	6.24 ha	0.3 acre	
Incremental	601 acres	243 ha	11.7 acres	
Personnel				
Construction	293 workers		5.7 workers	
Operation and maintenance	1.10×10^3 workers		21.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1977 $)		
Construction	$\$70.4 \times 10^6$ total	$\$1.37 \times 10^6$ total	
Operation and maintenance	$\$55.0 \times 10^6$/yr	$\$1.07 \times 10^6$/yr	
Environmental Controls			
	Not Determined		

UNDERGROUND COAL MINING – EASTERN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	Negligible			75 μg/m^3 annual*
Sulfur dioxide	↓			80 μg/m^3 annual*
Oxides of nitrogen				100 μg/m^3 annual*
Hydrocarbons				
Carbon monoxide				10 × 10^3 μg/m^3 annual*
Aldehydes				
Water Pollutants				
Total dissolved solids	20.1 × 10^3 tons	18.3 × 10^3 tonnes	392 tons	250 mg/l*
• Iron	1.03 tons	0.933 tonne	0.02 ton	0.3 mg/l*
• Manganese	5.14 tons	4.67 tonnes	0.1 ton	0.050 mg/l*
• Aluminum	87.3 tons	79.2 tonnes	1.7 ton	
• Zinc	1.02 tons	0.926 tonne	0.02 ton	5 mg/l*
• Nickel	1.02 tons	0.926 tonne	0.02 ton	0.046 mg/l*
• Strontium	10.3 tons	9.33 tonnes	0.2 ton	
• Chloride	653 tons	592 tonnes	12.7 tons	
• Fluoride	5.14 tons	4.67 tonnes	0.1 ton	
• Calcium carbonate	7.11 × 10^3 tons	6.45 × 10^3 tonnes	138 tons	
Total suspended solids	874 tons	793 tonnes	1.7 tons	
• Iron	10.3 tons	9.33 tonnes	0.2 ton	
Ammonia	15.4 tons	14.0 tonnes	0.3 ton	0.02 mg/l*
Sulfate	8.99 × 10^3 tons	8.16 × 10^3 tonnes	175 tons	250 mg/l*
Solid Wastes				
From sinking the mine shaft	128 tons	117 tonnes	2.5 tons	
From treating mine water runoff	107 × 10^3 tons	97.5 tonnes	2.09 × 10^3 tons	
From extraction process		Not Determined		
Thermal Discharge		Not Determined		
Noise Pollution		Not Determined		

*Regulatory compliance level.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary	2 × 10^6 tons	1.8 × 10^6 tonnes	39 × 10^3	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MAGNETOHYDRODYNAMIC SYSTEM

REFERENCE ENERGY SYSTEM

Seed material (potassium) is mixed with a finely ground coal, ionized at a high temperature, and passed through a magnetic field to generate electricity. System components include a pulverized coal burner (2 stage combustor), magnetohydrodynamic generators, a seed recovery system, and steam bottoming cycle.

FACILITY OPERATING PARAMETERS

Size:	1.932×10^3 MWe
Annual Capacity Factor:	65% (load factor)
Annual Energy Production:	37.5×10^{12} Btu (11×10^6 MWe)
Efficiency:	49.8%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal (bituminous)	3.60×10^6 tons	3.26×10^6 tonnes	96.9×10^3 tons	Illinois No. 6
Energy				
Potassium seed material		Not Determined		Information not available
Water				
Consumptive use	11.5×10^3 acre-ft	14.2×10^9 l	306 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land	1.77×10^3 acres	718 ha	47.3 acres	
Personnel				
Construction		Not Determined		
Operation and maintenance		↓		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1975 $)		
Construction	$1.4 × 10^9 total	$37 × 10^6 total	
Operation and maintenance	$37.5 × 10^6/yr	$1.00 × 10^6/yr	
Environmental Controls			
	Not Determined		

MAGNETOHYDRODYNAMIC SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	1.1×10^3 tons	1.0×10^3 tonnes	30 tons	
Sulfur dioxide	18.8×10^3 tons	17.0×10^3 tonnes	500 tons	
Oxides of nitrogen	11.2×10^3 tons	10.2×10^3 tonnes	300 tons	
Water Pollutants				
Blowdown from cooling and steam system – similar to emission from an electric power station				
Solid Wastes				
Furnace wastes	285×10^3 tons	259×10^3 tonnes	7.60×10^3 tons	
Fly ash	50.2×10^3 tons	45.6×10^3 tonnes	1.34×10^3 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electrical energy	11.0×10^9 kWh	11.0×10^9 kWh	0.293×10^9 kWh	
Byproducts				
Sulfur	116×10^3 tons	106×10^3 tonnes	3.10×10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BARGE TRANSPORTATION – EASTERN COAL

REFERENCE ENERGY SYSTEM

A barge tow system for transporting coal that consists of 15 barges, each with a capacity of 1400 tons. Total capacity of each tow is 21,000 tons of coal per trip. The 15-barge tow system is propelled by a single 4200-hp diesel-fueled towboat. For an average haul distance (one way) of 190 mi, an average speed of 9 mph, and approximately 3 wk reserved annually for maintenance and miscellaneous delays, an estimated 116 round trips are made annually.

FACILITY OPERATING PARAMETERS

Size:	21×10^3 tons/trip (propelled by a 4.2×10^3 hp diesel towboat)
Annual Capacity Factor:	94% (based on an average 3 wk/yr down time)
Annual Energy Production:	62.6×10^{12} Btu (coal transported)
Efficiency:	99.5% based on $\frac{\text{energy transported}}{\text{energy loaded + energy required}}$
Lifetime:	Not determined*

*Lifetime specified for analogous "Barge Transportation – Western Coal" is 30 years.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Coal transported	2.44×10^6 tons	2.21×10^6 tonnes	38.911×10^3 tons	Heat content = 12.85×10^3 Btu/lb
Energy				
Diesel fuel	284×10^9 Btu	300×10^{12} J	4.53×10^9 Btu	
Construction Materials				
Steel	3.82×10^3 tons	3.45×10^3 tonnes	61.0 tons	Includes carbon, alloy and stainless steel requirements
Copper	31.3 tons	28.4 tonnes	0.5 ton	
Aluminum	37.6 tons	34.1 tonnes	0.6 ton	
Manganese	31.3 tons	28.4 tonnes	0.5 ton	
Chromium	6.3 tons	5.7 tonnes	0.1 ton	
Cast iron	106 tons	96.2 tonnes	1.7 tons	
Personnel				
Construction		Not Determined		
Operation and maintenance	31.3 workers		0.5 worker	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$6.3 × 10^6 total	$0.1 × 10^6 total	
Operation and maintenance	$1.57 × 10^6/yr	$0.025 × 10^6/yr	Excludes diesel fuel costs
Environmental Controls			
	Not Determined		

BARGE TRANSPORTATION — EASTERN COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	34.4 tons	31.2 tonnes	0.55 ton	
Sulfur dioxide	32.6 tons	29.6 tonnes	0.52 ton	
Oxides of nitrogen	483 tons	438 tonnes	7.71 tons	
Hydrocarbons	38.8 tons	35.2 tonnes	0.62 ton	
Carbon monoxide	105 tons	95.3 tonnes	1.68 tons	
Water Pollutants				
The potential for water quality degradation exists due to shoreline erosion from towboat wake and spillage of coal and/or diesel fuel from the barge and towboat, respectively				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported (same as feed material)	2.44×10^6 tons	2.21×10^6 tonnes	38.911×10^3 tons	Heat content = 12.85×10^3 Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BARGE TRANSPORTATION – WESTERN COAL

REFERENCE ENERGY SYSTEM*

A barge tow system for transporting coal consisting of 15 barges, each with a capacity of 1400 tons. Total capacity of each tow is 21,000 tons of coal per trip. The 15-barge tow system is propelled by a single 4200-hp diesel-fueled towboat. For an average haul distance (one way) of 400 mi, average speed of 9 mph, average load/unload time (total) of 10 hr, 1 day layover per trip, and 21 days per year of scheduled maintenance, the system delivers 67.2 trips per year.

*This description and the following quantitative data presentation are based on estimates of how barge transportation of coal could develop in the West.

FACILITY OPERATING PARAMETERS

Size:	21×10^3 tons (coal)/trip (propelled by a 4.2×10^3 hp diesel-fueled towboat)
Annual Capacity Factor:	94% (based on an average of 3 wk/yr downtime)
Annual Energy Production:	26.7×10^{12} Btu (coal transported)
Efficiency:	98.7% based on $\frac{\text{energy transported}}{\text{energy loaded + energy required}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Coal transported	1.41×10^6 tons	1.28×10^6 tonnes	52.911×10^3 tons	Heat content = 9.45×10^3 Btu/lb
Energy				
Diesel fuel	347×10^9 Btu	366×10^{12} J	13.0×10^9 Btu	Diesel fuel consumed per 10^{12} Btu of coal transported
	Total Usage			
Construction Materials				
Total steel	3.82×10^3 tons	3.46×10^3 tonnes	143.2 tons	Carbon, alloy, and stainless steel
Copper	29.4 tons	26.7 tonnes	1.1 tons	
Aluminum	34.7 tons	31.5 tonnes	1.3 tons	
Manganese	29.4 tons	26.7 tonnes	1.1 tons	
Chromium	2.8 tons	2.5 tonnes	0.1 ton	
Cast iron	104 tons	94.3 tonnes	3.9 tons	
Personnel				
Construction	Not Determined			
Operation and maintenance	32.0 workers		1.20 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction	$5.34 × 10^6 total	$0.200 × 10^6 total	
Operation and maintenance	$1.50 × 10^6/yr	$0.056 × 10^6/yr	Operating costs exclude diesel fuel costs
Environmental Controls			
	Not Determined		

BARGE TRANSPORTATION – WESTERN COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates*	41.9 tons	38.0 tonnes	1.57 tons	
Sulfur dioxide	39.2 tons	35.6 tonnes	1.47 tons	
Oxides of nitrogen	588 tons	534 tonnes	22.03 tons	
Hydrocarbons	47.0 tons	42.6 tonnes	1.76 tons	
Carbon monoxide	128 tons	116 tonnes	4.79 tons	
Water Pollutants				
The potential for water quality degradation due to spillage of diesel fuel and/or coal exists; shoreline erosion, due to towboat wake, may also lead to increased sedimentation of waterways				

*Particulates are from diesel fuel combustion. Total suspended particulates (windage) from barge transport of coal are projected to be negligible due to low speeds and high moisture content

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Coal transported (same as feed material)	1.41×10^6 tons	1.28×10^6 tonnes	52.911×10^3 tons	Heat content = 9.45×10^3 Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

HIGH-VOLTAGE TRANSMISSION

REFERENCE ENERGY SYSTEM

A 345-kV alternating current (a.c.) line, 500 mi long with a right-of-way (ROW) width of 150 ft (18 acres/mi) serving 600-MWe power plant capacity. Typical components include (not exhaustive) stranded aluminum conductors, ground wires, conductor towers and insulators, and land for system ROW. Reference system is a single circuit with three conductors.

FACILITY OPERATING PARAMETERS

Size:	345-kV a.c. line (serving 600-MWe power capacity)
Annual Capacity:	65%
Annual Energy Production:	9.6×10^{12} Btu (2.8×10^{9} kWh) (electricity transmitted)
Efficiency:	82%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Electricity transmitted	3.4×10^{9} kWh	3.4×10^{9} kWh	0.354×10^{9} kWh	Total electrical input to line to generate output at 82% efficiency
	Total Usage			
Construction Materials				
Concrete	27.0×10^{3} tons	24.5×10^{3} tonnes	2.81×10^{3} tons	The listing pertains to typical materials used and is not exhaustive
Steel	24.2×10^{3} tons	22.0×10^{3} tonnes	2.52×10^{3} tons	
Copper	873 tons	792 tonnes	90.9 tons	
Aluminum	4.52×10^{3} tons	3.92×10^{3} tonnes	450 tons	
Manganese	169 tons	153 tonnes	17.6 tons	
Chromium	17.8 tons	16.2 tonnes	1.86 tons	
Nickel	220×10^{-3} ton	200×10^{-3} tonne	22.9×10^{-3} ton	
Cast iron	99.8 tons	90.6 tonnes	10.4 tons	
Land				
Right-of-way	4.30×10^{3} acres	1.74×10^{3} ha	447 acres	May be used simultaneously for other purposes
Personnel				
Construction (2 yr)	1.6×10^{3} workers		170 workers	
Operation and maintenance	7.2 workers		0.75 worker	No personnel required for system operation

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 \$)		
Construction (2 yr)	$\$154 \times 10^{6}$ total	$\$16.1 \times 10^{6}$ total	
Operation and maintenance	$\$0.212 \times 10^{6}$/yr	$\$0.0221 \times 10^{6}$/yr	Operating manpower is reported as zero
Environmental Controls			
	Not Determined		

HIGH-VOLTAGE TRANSMISSION

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Chemical oxidants, such as ozone, may be generated by the corona				
Noise Pollution				
Noise generated by the corona will not be loud enough to cause hearing damage				
Electromagnetic Fields				
Electric and magnetic fields from 345-kV lines may interfere with a few of the most sensitive cardiac pacemakers. Single circuit, 345-kV lines have maximum field strengths of 4.5 to 8 kV/m at 3 ft above the ground. For field strengths of 6 kV/m or more, annoying transient spark discharges may occur in some circumstances. Current research data indicate that subtle biological effects are occurring to laboratory animals at field strengths approaching 12 kV/m (referred to man).				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity transmitted (net)	2.81×10^9 kWh	2.81×10^9 kWh	0.293×10^9 kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

VERY HIGH VOLTAGE TRANSMISSION

REFERENCE ENERGY SYSTEM

A 500-kV alternating current (a.c.) line, 500 mi long with a right-of way (ROW) width of 175 ft (21 acres/mi) serving 1200-MW power plant capacity. Typical components include (not exhaustive) stranded aluminum conductors, steel ground wires, conductor towers, and insulators. Reference system is single circuit with three conductors.

FACILITY OPERATING PARAMETERS

Size:	500-kV a.c. line (serving 1200-MWe power capacity)
Annual Capacity Factor:	65%
Annual Energy Production:	20.8 × 10^{12} Btu (6.1 × 10^9 kWh) (electricity transmitted)
Efficiency:	89%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Electricity transmitted	6.84 × 10^9 kWh	6.84 × 10^9 kWh	0.329 × 10^9 kWh	0.329 × 10^9 kWh input to line required to generate 10^{12} Btu output at 89% efficiency
	Total Usage			
Construction Materials				
Concrete (including cement)	38.1 × 10^3 tons	34.6 × 10^3 tonnes	1.832 × 10^3 tons	
Steel	35.1 × 10^3 tons	31.8 × 10^3 tonnes	1.687 × 10^3 tons	
Copper	2.64 × 10^3 tons	2.40 × 10^3 tonnes	127 tons	
Aluminum	11.1 × 10^3 tons	10.1 × 10^3 tonnes	534 tons	
Manganese	229 tons	208 tonnes	11 tons	
Chromium	62 tons	57 tonnes	3 tons	
Nickel	2.1 tons	1.9 tonnes	0.1 ton	
Cast iron	125 tons	113 tonnes	6 tons	
Land				
Right-of-way	10.6 × 10^3 acres	4.30 × 10^3 ha	509.9 acres	May be used simultaneously for other purposes
Personnel				
Construction (2 yr)	2.28 × 10^3 workers		109.8 workers	
Operation and maintenance	12.5 workers		0.6 worker	No personnel required for system operation

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (2 yr)	\$239 × 10^6 total	\$11.51 × 10^6 total	
Operation and maintenance	\$0.374 × 10^6/yr	\$0.01799 × 10^6/yr	
Environmental Controls			
	Not Determined		

VERY HIGH VOLTAGE TRANSMISSION

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Chemical oxidants, such as ozone, may be generated by the corona				
Noise Pollution				
Noise generated by the corona will not be loud enough to cause hearing damage				
Electromagnetic Fields				
Electric and magnetic fields from 500-kV lines will probably interfere with some cardiac pacemakers. Single-circuit, 500-kV lines have maximum field strengths of 6 to 7 kV/m at 3 ft above the ground. This is strong enough to result in annoying transient spark discharges under some circumstances. Current research data indicate that subtle biological effects are occurring to laboratory animals at field strengths approaching 12 V/m (referred to man).				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity transmitted (net)	6.09×10^9 kWh	6.09×10^9 kWh	0.293×10^9 kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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PETROLEUM TECHNOLOGIES

The following should be recognized as limitations of the information provided on the summary sheets of this section:

1. The impacts and costs of oil and gas operations vary widely over the period of development. Typically, capital costs will be concentrated in the initial phases of development, and operation and maintenance costs and impacts will be spread over a longer period of time. Annualizing costs and impacts over the life cycle of a project ignores the actual pattern in which they occur.

2. The figures presented in the data sheets apply to specific representative cases. The variation around these cases may be quite extensive. Some costs, such as platforms, will vary geometrically rather than arithmetically. Thus, an 18-well platform in 400 feet of water will be much more than twice as expensive than one in 200 feet of water. Unless production per platform changes in exactly the same proportion, the numbers provided in the data sheets may be unrealistic.

3. The data sheets also do not consider changes in the underlying conditions determining the economic limit for oil and gas development. The rapid escalation of crude oil prices and changes in price/cost relationships will bring formerly uneconomic projects into production. These projects will generally have unit cost characteristics that are very different from the "representative" projects shown on the data sheets. It is likely that for these new projects, the costs per 10^{12} Btu produced will be much higher. The estimates of environmental impact also do not include the fact that many of the new projects will have improved environmental control systems that are not yet defined. For example, new steam Enhanced Oil Recovery projects will be required to have air emission levels that are much lower than the national averages shown on the data sheets.

OIL-FIRED STEAM ELECTRIC POWER PLANT

REFERENCE ENERGY SYSTEM

An oil-fired steam electric power plant generating electricity using the same basic unit processes as other fossil-fueled power stations (e.g., coal and natural-gas-fired systems). Basically, the chemical energy in the fuel oil is converted to heat energy in the steam generator (boiler), the output of which drives a turbine/generator (mechanical/electrical energy), which produces electricity. The power plant includes the following environmental control components as part of the total system: electrostatic precipitator, sulfur dioxide scrubber, wastewater treatment system, sludge dewatering system, and a solid waste disposal system.

FACILITY OPERATING PARAMETERS

Size:	800 MWe
Annual Capacity Factor:	55%
Annual Energy Production:	13.15×10^{12} Btu
Efficiency:	34.7%
Lifetime:	35 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Residual fuel oil No. 6	6.18×10^6 bbl	982×10^6 l	470×10^3 bbl	Heat content of fuel oil = 6.13×10^6 Btu/bbl
Energy				
Average energy requirements for environmental control devices	0.29×10^9 kWh	0.29×10^9 kWh	0.022×10^9 kWh	Total energy requirement is approximately 7.5% of energy generated
Processing Materials		Not Determined		
Water				
Once-through evaporative cooling towers	3.3×10^3 acre-ft	4.1×10^9 l	250 acre-ft	
• Mechanical draft	$<7.2 \times 10^3$ acre-ft	$<8.9 \times 10^9$ l	<550 acre-ft	
• Natural draft	$<7.2 \times 10^3$ acre-ft	$<8.9 \times 10^9$ l	<550 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land	96 acres	39 ha	7.3 acres	When using mechanical draft cooling towers
Personnel				
Construction (5 yr)	1.67×10^3 workers		127 workers	
Operation and maintenance	138 workers		10.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (5 yr)	$\$240 \times 10^6$ total	$\$18 \times 10^6$ total	
Operation and maintenance	$\$6.35 \times 10^6$/yr	$\$0.483 \times 10^6$/yr	
Environmental Controls			
Capital	$\$36.3 \times 10^6$ total	$\$2.76 \times 10^6$ total	Capital costs assume use of draft evaporative cooling towers; costs applicable to new equipment only, not retrofit cases
Operation and maintenance	$\$6.98 \times 10^6$/yr	$\$0.531 \times 10^6$/yr	Costs applicable to new equipment only, not retrofit cases

OIL-FIRED STEAM ELECTRIC POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Total suspended particulates	5.39×10^3 tons	4.89×10^3 tonnes	410 tons	15 tons/10^{12} Btu*
Sulfur dioxide	48.9×10^3 tons	44.4×10^3 tonnes	3.72×10^3 tons	100 tons/10^{12} Btu*
Oxides of nitrogen	5.68×10^3 tons	5.16×10^3 tonnes	432 tons	500 tons/10^{12} Btu*
Hydrocarbons	130 tons	120 tonnes	9.8 tons	
Carbon monoxide	648 tons	588 tonnes	49.3 tons	
Particulates/arsenic	0.127 ton	0.115 tonne	9.63×10^{-3} ton	
Particulates/beryllium	0.101 ton	91.8×10^{-3} tonne	7.69×10^{-3} ton	
Particulates/cadmium	3.79 tons	3.44 tonnes	0.288 ton	
Particulates/lead	20.2×10^{-3} ton	18.4×10^{-3} tonne	1.54×10^{-3} ton	
Particulates/mercury	0.127 ton	0.115 tonne	9.63×10^{-3} ton	
Particulates/nickel	37.9 tons	34.4 tonnes	2.88 tons	
Particulates/manganese	0.127 ton	0.115 tonne	9.63×10^{-3} ton	
Particulates/chromium	0.297 ton	0.270 tonne	22.6×10^{-3} ton	
Particulates/copper	0.297 ton	0.270 tonne	22.6×10^{-3} ton	
Particulates/vanadium	0.598 ton	0.543 tonne	45.5×10^{-3} ton	
Water Pollutants**				
Biochemical oxygen demand	67.8 tons	61.6 tonnes	5.16 tons	
Chemical oxygen demand	509 tons	462 tonnes	38.7 tons	
Total suspended solids	910 tons	826 tonnes	69.2 tons	
Total dissolved solids	5.06×10^3 tons	4.60×10^3 tonnes	385 tons	
Ammonia	0.977 ton	0.887 tonne	74.3×10^{-3} ton	
Solid Wastes***				
Total solid wastes	216×10^3 tons	196×10^3 tonnes	16.4×10^3 tons	Scrubber sludge and particulate combined
Thermal Discharge				
Total thermal loss	24.7×10^{12} Btu	26.1×10^{15} J	1.88×10^{12} Btu	Stack, cooling water, and miscellaneous losses

*Regulatory compliance level.

**Water pollutants assuming a closed-cycle system.

***With nonregenerative scrubbers; 2% sulfur content is assumed with 90% removal efficiency.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	3.65×10^9 kWh	3.85×10^9 kWh	0.293×10^9 kWh	
Byproducts/Recoverables/Recyclables		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	23.8×10^{-3}	1.81×10^{-3}	
Injuries	2.27	0.173	
Manyears Lost	0.1	0.01	

CRUDE OIL STORAGE IN SALT DOME CAVERNS

REFERENCE ENERGY SYSTEM

The salt dome caverns are created by leaching with water; the resulting brine is discharged into a large body of water such as the Gulf of Mexico in an environmentally acceptable manner or recovered for use in the chemical industry. These caverns are provided with a cemented casing to protect subsurface water quality and with pipelines to handle water/brine and crude oil.

FACILITY OPERATING PARAMETERS

Size:	60×10^6 bbl (336×10^{12} Btu)
Annual Capacity Factor:	100%
Annual Energy Production:	Annual values for storage not available
Efficiency:	Not determined
Lifetime:	Not determined

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage*		Per 10^{12} Btu Energy Produced**	Remarks
	English Units	Metric Units		
Feed Materials				
Crude oil stored			178.572×10^3 bbl	
Energy				
Electric power to operate pumps		Not Determined		
Water				
Initial leaching operation			173 acre-ft	56.25×10^6 gal crude withdrawal
Each pumping operation			24 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land			2.4 acres	Site plus pipelines
Personnel				
Construction			0.6 worker	
Operation and maintenance		Not Determined		

*Annual values for storage not available.
**Energy produced in this case means energy stored.

COSTS

	Reference Energy System*	Per 10^{12} Btu Energy Produced**	Remarks
Facility			
	(1976 $)		
Construction		$\$0.23 \times 10^6$ total	
Operation and maintenance	Not Determined		
Environmental Controls			
	Not Determined		

*Annual values for storage not available.
**Energy produced in this case means energy stored.

CRUDE OIL STORAGE IN SALT DOME CAVERNS

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels*			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced**	Remarks
Air Pollutants				
Hydrocarbons			2.27 tons	
Water Pollutants				
Hydrocarbons		Not Determined		
Brine discharged				
• Initial leaching operation			196 acre-ft	
• Each crude oil fill operation			21 acre-ft	
Solid Wastes				
		Negligible During Operation		
Noise Pollution				
		Not Determined		

*Annual values for storage not available.
**Energy produced in this case means energy stored.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production*			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced**	Remarks
Primary				
Crude oil stored (same as feed material)			178.572×10^3 bbl	

*Annual values for storage not available.
**Energy produced in this case means energy stored.

OCCUPATIONAL SAFETY AND HEALTH*

Not Determined

*One death and one major injury have occurred to date in connection with the Strategic Petroleum Reserve storage facilities, which now contain over 115 million bbl.

ONSHORE ENHANCED OIL RECOVERY—STEAM INJECTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

Enhanced oil recovery via continuous injection of steam through special wells. Due to changes in the viscosity and volume (expansion) of oil and possible rock permeability, oil is displaced by water derived from condensed steam. The recovered oil-water-gas mixture is treated in a separation unit. The energy product derived is crude oil with an average heat content of 6.3×10^6 Btu/bbl.

FACILITY OPERATING PARAMETERS

Size:	52.65×10^3 bbl/day of enhanced oil recovery (1382 wells)
Annual Capacity Factor:	70%
Annual Energy Production:	84.7×10^{12} Btu
Efficiency:	10% (of original-oil-in-place)
Lifetime:	15 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Process steam		Not Determined		Refer to water resources used
Energy		Not Determined		
Processing Materials		Not Determined		
Water				
Process steam	8.64×10^3 acre-ft	10.7×10^9 l	102 acre-ft	
	Total Usage			
Construction Materials				
Concrete	127×10^3 tons	115×10^3 tonnes	1.50×10^3 tons	
Total steel	78.0×10^3 tons	70.8×10^3 tonnes	921 tons	
Oil country tubular goods	38.9×10^3 tons	35.4×10^3 tonnes	460 tons	
Land	3.51×10^3 acres	1.42×10^3 ha	41.4 acres	
Personnel				
Construction (2 yr)	280 workers		3.3 workers	
Operation and maintenance	780 workers		9.2 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (2 yr)	$\$506 \times 10^6$ total	$\$5.97 \times 10^6$ total	
Operation and maintenance	$\$95.7 \times 10^6$/yr	$\$1.13 \times 10^6$/yr	
Environmental Controls	Not Determined		

ONSHORE ENHANCED OIL RECOVERY—STEAM INJECTION—LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants				
Particulates	2.0×10^3 tons	1.8×10^3 tonnes	24 tons	15 tons/10^{12} Btu*
Sulfur dioxide	17.5×10^3 tons	15.9×10^3 tonnes	207 tons	100 tons/10^{12} Btu*
Oxides of nitrogen	6.0×10^3 tons	5.4×10^3 tonnes	71 tons	500 tons/10^{12} Btu*
Hydrocarbons	170 tons	150 tonnes	2.0 tons	
Carbon monoxide	350 tons	320 tonnes	4.1 tons	
Water Pollutants				
Hydrocarbons	70-330 tons	60-300 tonnes	0.8-3.9 tons	
Solid Wastes				
Quantities are process and site specific				
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

*Regulatory compliance levels.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Crude oil	34.5×10^6 bbl	2.14×10^9 l	159×10^3 bbl	Heat content of crude is 6.3×10^6 Btu/bbl
Recoverables/Recyclables				
Water		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ONSHORE PRIMARY OIL EXTRACTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

400-well production field. 195 unproductive wells (dry holes) are plugged with cement and crimped below ground level. Gathering pipeline routes oil to field processing facility for gas-water-oil separation. Success ratio for exploration wells is 27.4% and for production wells, 67.2%.

FACILITY OPERATING PARAMETERS

Size:	0.1 × 10^6 bbl/day (250 bbl/well/day)
Annual Capacity Factor:	100%
Annual Energy Production:	212 × 10^{12} Btu
Efficiency:	30% (oil reservoir recovery)
Lifetime:	26 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Energy				
Electric pumps	1.34 × 10^{12} Btu	1.41 × 10^{15} J	6.32 × 10^9 Btu	
Heater treater separators	0.18 × 10^{12} Btu	0.19 × 10^{15} J	0.94 × 10^9 Btu	
Diesel fuel for development drilling	1.6 × 10^{12} Btu	1.7 × 10^{15} J	7.6 × 10^9 Btu	
	Total Usage			
Construction Materials				
Concrete (mixed)	20.0 × 10^3 tons	18.1 × 10^3 tonnes	94.3 tons	
Pipe and tubing	72.0 × 10^3 tons	65.4 × 10^3 tonnes	339.6 tons	
Reinforcing bars	4.01 × 10^3 tons	3.64 × 10^3 tonnes	18.9 tons	
Refined products	700 × 10^3 tons	635 × 10^3 tonnes	3.3019 × 10^3 tons	
Oil country tubular goods	560 × 10^3 tons	508 × 10^3 tonnes	2.642 × 10^3 tons	
Pumps and drivers	3.20 × 10^3 tons	2.91 × 10^3 tonnes	15.1 tons	
Water				
Production drilling fluid	10.2 acre-ft*	12.6 × 10^6 l*	0.0482 acre-ft	
Land	2.00 × 10^3 acres	809 ha	9.43 acres	
Personnel				
Construction (7 yr)	2.80 × 10^3 workers		13.2 workers	
Operation and maintenance	2.0 × 10^3 workers		9.7 workers	

*Total life cycle values during 7-yr drilling and facility construction period.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (7 yr)	\$3.03 × 10^9 total	\$14.287 × 10^6 total	
Operation and maintenance	\$26.7 × 10^6/yr	\$0.126 × 10^6/yr	
Environmental Controls			
	Not Determined		

ONSHORE PRIMARY OIL EXTRACTION – LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Oxides of nitrogen	3.94×10^3 tons	3.58×10^3 tonnes	18.6 tons	Air pollutants produced during drilling and production
Carbon monoxide	110 tons	100 tonnes	0.5 ton	
Hydrocarbons	2.25×10^3 tons	2.04×10^3 tonnes	10.6 tons	
Oxides of sulfur	2.88×10^3 tons	2.62×10^3 tonnes	13.6 tons	
Particulates	740 tons	670 tonnes	3.5 tons	
Solid Wastes				
Drilling cuttings, barite, bentonite, and phosphate	200×10^3 tons*	182×10^3 tonnes*	946 tons	
Noise Pollution				
		Not Determined		

*Solid wastes are total life cycle values over the 7-yr drilling and facility construction period.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Crude Oil	36.5×10^6 bbl	5.81×10^9 l	172.4×10^3 bbl	5.8×10^6 Btu/bbl

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	0.4	0.002	
Injuries	43.0	0.203	
Man-days lost	7.15×10^3	33.745	

OFFSHORE OIL EXTRACTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

The reference energy system is composed of an 18-well offshore platform capable of producing 4 × 10³ bbl/day of oil. Wells are drilled to an average depth of 9500 ft. The development well success rate equals ≅76%. 18 months would be required to complete drilling, but production could be started before that date. Direction drilling techniques are used from the platform. Six dry holes (including three during exploration) are plugged with cement and the casing crimped 15 ft below the sea floor.

FACILITY OPERATING PARAMETERS

Size:	4 × 10³ bbl/day per platform
Annual Capacity Factor:	100%
Annual Energy Production:	8.47 × 10^{12} Btu
Efficiency:	40% (reservoir recovery efficiency)
Lifetime:	15–20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Energy				
Fuel for drilling	572 × 10^9 Btu*	603 × 10^{12} J*	67.5 × 10^9 Btu	
Prime mover pumps	8.89 × 10^9 Btu	9.38 × 10^{12} J	1.05 × 10^9 Btu	
Heater treater	53.6 × 10^9 Btu	56.6 × 10^{12} J	6.33 × 10^9 Btu	
Other production and support requirements	125 × 10^9 Btu	132 × 10^{12} J	14.8 × 10^9 Btu	
Water				
Drilling mud water (fresh or salt)	0.240 acre-ft*	0.297 × 10^6 l*	28.4 × 10^{-3} acre-ft	Assumed 31.5 gal/bbl
Fresh water for workers	1.61 acre-ft	1.98 × 10^6 l	190 × 10^{-3} acre-ft	↑
	Total Usage			
Construction Materials				
Concrete		Not Determined		
Barite and bentonite		↓		
Steel		↓		
Copper, aluminum, manganese nickel, and chromium		↓		
Iron, steel, aluminum, and brass castings		↓		
Structural steel and steel plates		↓		
Pipe, tubular goods, and valves		↓		
Land				
Water surface area	2.01 × 10^3 acres	812 ha	237 acres	If 1-mi fishing buffer is included in permit
Personnel				
Construction (1½ yr)	45–65 workers		5.3–7.7 workers	
Operation and maintenance	16 workers		1.9 workers	

*Total life cycle values during 1½ yr drilling period.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (1½ yr)	\$56.5 × 10^6 total	\$6.67 × 10^6 total	
Operation and maintenance	\$2.05 × 10^6/yr	\$0.242 × 10^6/yr	
Environmental Controls	Not Determined		

OFFSHORE OIL EXTRACTION – LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released: Reference Energy System Annual Levels – English Units	Quantities Released: Reference Energy System Annual Levels – Metric Units	Quantities Released: Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Oxides of nitrogen	270 tons	245 tonnes	31.92 tons	
Carbon monoxide	58.5 tons	53.1 tonnes	6.91 tons	
Hydrocarbons (exhaust)	21.6 tons	19.6 tonnes	2.55 tons	
Particulates	19.3 tons	17.5 tonnes	2.28 tons	
Oxides of sulfur	100 tons	90.6 tonnes	11.79 tons	
Water Pollutants				
Cadmium	0.204 ton	0.185 tonne	24.1×10^{-3} ton	
Cyanide	30.0×10^{-3} ton	27.2×10^{-3} tonne	3.54×10^{-3} ton	
Mercury	1.52×10^{-3} ton	1.38×10^{-3} tonne	0.18×10^{-3} ton	
Total organic carbon (including oil)	1.24×10^{3} tons	1.12×10^{3} tonnes	146.34 tons	
Total suspended solids	219 tons	199 tonnes	25.867 tons	
Total dissolved solids	330×10^{3} tons	300×10^{3} tonnes	38.977×10^{3} tons	
Chlorides	183×10^{3} tons	166×10^{3} tonnes	21.615×10^{3} tons	
Solid Wastes				
Drill cuttings	26.6×10^{3} tons*	24.1×10^{3} tonnes*	3.136×10^{3} tons	9500-ft wells
Drilling muds	4.67×10^{3} tons*	4.24×10^{3} tonnes*	551.0 tons	
Noise Pollution				
		Not Determined		

*Solid waste values are total life cycle values during the 1½-yr drilling period.

PRODUCTS

	Quantities Produced: Reference Energy System Annual Production – English Units	Quantities Produced: Reference Energy System Annual Production – Metric Units	Quantities Produced: Per 10^{12} Btu Energy Produced	Remarks
Primary				
Crude oil	1.46×10^{6} bbl	0.232×10^{9} l	0.172×10^{6} bbl	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths*	27.1×10^{-3}	32×10^{-3}	
Injuries*	41.5×10^{-3}	4.9×10^{-3}	

*1970-1977 sum of injuries and fatalities due to blowouts, fire and explosions, and miscellaneous accidents occurring during exploration, development, and production.

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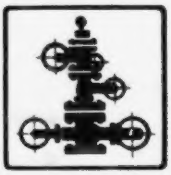

NATURAL GAS TECHNOLOGIES

The following should be recognized as limitations of the information provided on the summary sheets of this section:

1. The impacts and costs of oil and gas operations vary widely over the period of development. Typically, capital costs will be concentrated in the initial phases of development, and operation and maintenance costs and impacts will be spread over a longer period of time. Annualizing costs and impacts over the life cycle of a project ignores the actual pattern in which they occur.

2. The figures presented in the data sheets apply to specific representative cases. The variation around these cases may be quite extensive. Some costs, such as platforms, will vary geometrically rather than arithmetically. Thus, an 18-well platform in 400 feet of water will be much more than twice as expensive than one in 200 feet of water. Unless production per platform changes in exactly the same proportion, the numbers provided in the data sheets may be unrealistic.

3. The data sheets also do not consider changes in the underlying conditions determining the economic limit for oil and gas development. The rapid escalation of crude oil prices and changes in price/cost relationships will bring formerly uneconomic projects into production. These projects will generally have unit cost characteristics that are very different from the "representative" projects shown on the data sheets. It is likely that for these new projects, the costs per 10^{12} Btu produced will be much higher. The estimates of environmental impact also do not include the fact that many of the new projects will have improved environmental control systems that are not yet defined.

GAS-FIRED STEAM ELECTRIC POWER PLANT

REFERENCE ENERGY SYSTEM

Gas fired steam electric power plant generating electricity using steam produced in a boiler from heat supplied from natural gas combustion to drive a turbine/generator system that produces electricity.

FACILITY OPERATING PARAMETERS

Size:	800 MWe
Annual Capacity Factor:	55%
Annual Energy Production:	13.15×10^{12} Btu
Efficiency:	37%
Lifetime:	35 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Natural gas (fuel)	34.7×10^9 ft^3	0.983×10^9 m^3	2.64×10^9 ft^3	Heat content of fuel is 1.02×10^3 Btu/ft^3
Energy				
Environmental control devices (energy requirements)	$<127 \times 10^6$ kWh	$<127 \times 10^6$ kWh	$<9.67 \times 10^6$ kWh	Less than 3.3% of energy generated
Water				
Once-through (consumptive water use only)	3.00×10^3 acre-ft	3.70×10^9 l	228 acre-ft	Cooling towers can also be used as cooling system
	Total Usage			
Construction Materials				
	Not Determined			
Land				
Fixed land area	88.8 acres	35.9 ha	6.75 acres	Includes average of land range given for cooling towers
Personnel				
Construction (4 yr)	1.20×10^3 workers		91.5 workers	
Operation and maintenance	108 workers		8.20 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 \$)		
Construction (4 yr)	\$146 × 10^6 total	\$11.1 × 10^6 total	
Operation and maintenance	\$5.19 × 10^6/yr	\$0.395 × 10^6/yr	
Environmental Controls			
Construction	\$31.4 × 10^6 total	\$2.39 × 10^5 total	
Operation and maintenance	\$0.368 × 10^6/yr	\$0.028 × 10^6/yr	

GAS-FIRED STEAM ELECTRIC POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Total suspended particulates	564 tons	512 tonnes	42.9 tons	
Sulfur dioxide	10.4 tons	9.44 tonnes	0.791 ton	
Oxides of nitrogen	12 × 10^3 tons	11 × 10^3 tonnes	0.93 × 10^3 tons	
Hydrocarbons (as methane)	17.3 tons	15.7 tonnes	1.32 tons	
Carbon monoxide	295 tons	268 tonnes	22.4 tons	
Water Pollutants*				
Biochemical oxygen demand	5.21 tons	4.73 tonnes	0.396 ton	
Chemical oxygen demand	439 tons	399 tonnes	33.4 tons	
Total suspended solids	909 tons	825 tonnes	69.1 tons	
Total dissolved solids	849 tons	771 tonnes	64.6 tons	
Ammonia	0.973 ton	0.883 tonne	0.074 ton	
Thermal Discharge				
Total heat losses (stack, cooling water, and miscellaneous)	23.3 × 10^{12} Btu	24.5 × 10^{15} J	1.77 × 10^{12} Btu	

*Water pollutants from open cycle system only.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	3.85 × 10^9 kWh	3.85 × 10^9 kWh	0.293 × 10^9 kWh	
Recoverables/Recyclables				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	0.023	1.75 × 10^{-3}	
Injuries	2.20	0.167	
Manyears Lost	0.1	0.01	

NATURAL GAS TRANSMISSION PIPELINE

REFERENCE ENERGY SYSTEM

A 600-mi underground steel pipeline constructed of 30 in. O.D. × 0.625 in. thick American Petroleum Institute 5LX60 pipe and operating at 1200 psig maximum allowable pressure. Natural gas is driven by six centrifugal compressors located at 100-mi intervals. The compressors are driven by gas turbines fueled by the natural gas in the pipeline. A metering station is located at each end of the pipeline.

FACILITY OPERATING PARAMETERS

Size:	600 × 10^6 scf/day
Annual Capacity Factor:	88%
Annual Energy Production:	190.488 × 10^{12} Btu (natural gas transmitted)
Efficiency:	96.9%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Natural gas transmitted	193 × 10^9 scf (196 × 10^{12} Btu)	5.46 × 10^9 m^3 (207 × 10^{15} J)	1.0117 × 10^9 scf (1.03 × 10^{12} Btu)	1.02 × 10^3 Btu/scf
Energy				
Fuel gas	5.96 × 10^9 scf (6.08 × 10^{12} Btu)	169 × 10^6 m^3 (6.42 × 10^{15} J)	31.3 × 10^6 scf (0.03193 × 10^{12} Btu)	
Water				
Temporary use	328 acre-ft	404 × 10^6 l	1.72 acre-ft	Hydrostatic testing
Well capacity at compressor stations	182 acre-ft	224 × 10^6 l	0.955 acre-ft	
	Total Usage			
Construction Materials				
Steel	0.313 × 10^6 tons	0.284 × 10^6 tonnes	1643.25 tons	
Land	12.0 × 10^3 acres	4.85 × 10^3 ha	62.91 acres	
Personnel				
Construction	1.32 × 10^3 workers		6.92 workers	
Operation and maintenance	40 workers		0.21 worker	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	\$280 × 10^6 total	\$1.468 × 10^6 total	
Operation and maintenance	Not Determined		
Environmental Controls			
	Not Determined		

NATURAL GAS TRANSMISSION PIPELINE

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates		Not Determined		
Oxides of nitrogen	762 tons	692 tonnes	4.001 tons	
Carbon monoxide	289 tons	262 tonnes	1.518 tons	
Hydrocarbons	52.6 tons	47.7 tonnes	0.2759 ton	
Oxides of sulfur	1.0 ton	0.95 tonne	5.5×10^{-3} ton	
Water Pollutants				
Construction activities, particularly stream crossings, may temporarily increase stream sediment loadings; normal operation should not affect water quality				
Noise Pollution*				
Construction				
• Right-of-way		90 dBA		
• Blasting		121 dBA		
Operation				
• Compressor stations (property boundary)		<60 dBA		

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Natural gas transmitted (net)	187×10^9 scf (190×10^{12} Btu)	5.30×10^9 m^3 (201×10^{15} J)	980.392×10^6 scf (1×10^{12} Btu)	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

LIQUEFIED NATURAL GAS TANKER

REFERENCE ENERGY SYSTEM

A 63,460-dead weight-ton tanker with five 25,000-m^3 insulated cryogenic tanks to hold liquefied methane at −260°F. Ship length, 289 m; beam, 41 m; design draft, 11 m; maximum shaft horsepower, 40,000; 35 crew accommodations; service speed, 20 knots. Ship is double hulled with one propeller.

FACILITY OPERATING PARAMETERS

Size:	125×10^3 m^3/tanker (2.6×10^9 ft^3/tanker)
Annual Capacity Factor:	95.3%
Annual Energy Production:	31.053×10^{12} Btu (12 trips/yr)
Efficiency:	95.8% (% cargo delivered)
Lifetime:	25 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Energy				
Boil-off burned to power tanker	916×10^9 Btu	0.966×10^{15} J	29.5×10^9 Btu	1.02×10^3 Btu/scf natural gas
Fuel oil to power tanker	857×10^9 Btu	0.904×10^{15} J	27.6×10^9 Btu	
Boil-off vented	240×10^9 Btu	0.253×10^{15} J	7.72×10^9 Btu	
Water				
	30.6×10^9 gal	116×10^9 l	984.25×10^6 gal	
	Total Usage			
Construction Materials				
Steel	33.9×10^3 tons	30.8×10^3 tonnes	1.092×10^3 tons	
Copper	267 tons	242 tonnes	8.602 tons	
Aluminum	111 tons	101 tonnes	3.575 tons	
Manganese	290 tons	261 tonnes	9.274 tons	
Chromium	1.06×10^3 tons	958 tonnes	34.004 tons	
Nickel	524 tons	475 tonnes	16.864 tons	
Cast iron	115 tons	104 tonnes	3.691 tons	
Personnel				
Construction (3 yr)	2.40×10^3 workers		77.287 workers	
Operation and maintenance	35.0 workers		1.127 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 \$)		
Construction (3 yr)	$\$0.200 \times 10^9$ total	$\$6.44 \times 10^6$ total	
Operation and maintenance	$\$27.3 \times 10^6$/yr	$\$0.879 \times 10^6$/yr	
Environmental Controls			
	Not Determined		

LIQUEFIED NATURAL GAS TANKER

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	75.7 tons	68.7 tonnes	2.438 tons	
Oxides of sulfur	231 tons	209 tonnes	7.424 tons	
Oxides of nitrogen	181 tons	165 tonnes	5.842 tons	
Hydrocarbons	16.3 tons	14.8 tonnes	0.524 ton	
Carbon monoxide	12.6 tons	11.4 tonnes	0.405 ton	
Methane vented	5.17×10^3 tons	4.69×10^3 tonnes	166.52 tons	
Water Pollutants				
Unknown water volume from shipboard boil-off condenser; excess heat rejected to seawater				
Thermal Discharge				
At sea = 5.9°F above ambient In port = 7.4°F above ambient				
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Liquefied natural gas (equivalent to)	669×10^3 tons	608×10^3 tonnes	21.557×10^3 tons	Quantity transported
Natural gas	30.4×10^9 scf	0.862×10^9 m^3	980.392×10^6 scf	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ONSHORE GAS EXTRACTION – LOWER 48 STATES

REFERENCE ENERGY SYSTEM

The reference energy system is composed of 120 gas wells in a single production field. These wells would be drilled to an average depth of 5000 ft with a success ratio of approximately 67%. The total exploration, drilling, and facility construction period would require 5 yr with some wells ready for production prior to this time. Dry holes (60 expected) would be plugged with cement and the casing would be crimped below the surface.

FACILITY OPERATING PARAMETERS

Size:	29.6×10^6 ft^3/day
Annual Capacity Factor:	100%
Annual Energy Production:	10.8×10^{12} Btu
Efficiency:	70% (50-90%) (gas reservoir recovery)
Lifetime:	15-25 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Energy				
Gas processing				
• Sweet gas	3.34×10^{12} Btu	3.52×10^{15} J	309.2×10^9 Btu	
• Sour gas	9.72×10^{12} - 14.7×10^{12} Btu	10.2×10^{15} - 15.6×10^{15} J	900×10^9 - 1.365×10^{12} Btu	
Development drilling (diesel fuel)	779×10^9 Btu	822×10^{12} J	72.1×10^9 Btu	
	Total Usage			
Construction Materials				
Cement/concrete	44.4×10^3 tons	40.4×10^3 tonnes	4.116×10^3 tons	
Pipe, tubing, valves	15.0×10^3 tons	13.6×10^3 tonnes	1.392×10^3 tons	
Steel (structural and casings)	17.4×10^3 tons	15.8×10^3 tonnes	1.614×10^3 tons	
Copper, aluminum, manganese, and other metals	364 tons	330 tonnes	33.7 tons	
Bentonite/barite	2.66×10^3 tons	2.41×10^3 tonnes	246 tons	
Water				
Drilling mud fluid	93.6 acre-ft*	116×10^6 l*	8.67 acre-ft	Assumed 31.5 gal/bbl
Land				
Temporary	511 acres	207 ha	47.36 acres	
Permanent	420 acres	170 ha	38.93 acres	
Personnel				
Construction (5 yr)	470 workers		43.48 workers	
Operation and maintenance	52.2 workers		4.83 workers	

*Water values are the total life cycle values during 5-yr drilling and facility construction period for 152 wells.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978$)		
Construction and drilling (5 yr)	$116 × 10^6 total	$10.71 × 10^6 total	
Operation and maintenance	$5.26 × 10^6/yr	$0.487 × 10^6/yr	
Environmental Controls			
	Not Determined		

ONSHORE GAS EXTRACTION – LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Oxides of nitrogen	915 tons	830 tonnes	84.7 tons	
Carbon monoxide	20 tons	19 tonnes	1.9 tons	
Hydrocarbons	6.5 tons	5.9 tonnes	0.6 ton	
Oxides of sulfur	15.4 × 10^3 tons	14.0 × 10^3 tonnes	1.425 × 10^3 tons	
Particulates	20 tons	19 tonnes	1.9 tons	
Water Pollutants				
Biochemical oxygen demand	18.5 tons	16.8 tonnes	1.71 tons	Water pollutants from processing plant
Chemical oxygen demand	121 tons	110 tonnes	11.20 tons	
Oil and grease	370 tons	336 tonnes	34.27 tons	
Chromium	1 ton	0.9 tonne	0.09 ton	
Zinc	0.32 ton	0.29 tonne	0.03 ton	
Total dissolved solids	4.94 × 10^3 tons	4.48 × 10^3 tonnes	457 tons	
Chloride	925 tons	840 tonnes	85.68 tons	
Sulfate	740 tons	672 tonnes	68.54 tons	
Solid Wastes				
Drill cuttings	36.3 × 10^3 tons*	33.0 × 10^3 tonnes*	3.364 × 10^3 tons	

*Solid waste values are the total life cycle values during 5-yr drilling and facility construction period for 152 5000-ft-deep wells.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Natural gas	10.8 × 10^9 ft^3	0.306 × 10^9 m^3	1.00 × 10^9 ft^3	1000 Btu/scf

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	56 × 10^{-6}	5.2 × 10^{-6}	
Injuries	30 × 10^{-3}	3 × 10^{-3}	
Man-days lost	0.32	0.030	

OFFSHORE GAS EXTRACTION – LOWER 48 STATES

REFERENCE ENERGY SYSTEM

The reference energy system is composed of an 18-well platform producing 88.722 × 10^6 ft^3 of natural gas (1000 Btu/scf) per day. Many of the wells are deviated with an average depth of 9.6 × 10^3 ft. Six dry holes are expected and are plugged with cement and the casing crimped 15 ft below the seafloor.

FACILITY OPERATING PARAMETERS

Size:	88.722 × 10^6 ft^3/day/platform
Annual Capacity Factor:	100%
Annual Energy Production:	32.4 × 10^{12} Btu
Efficiency:	50-90% (recovery efficiency)
Lifetime:	15-25 yr

RESOURCES USED

	Quantities Used: Reference Energy System Annual Usage – English Units	Quantities Used: Reference Energy System Annual Usage – Metric Units	Quantities Used: Per 10^{12} Btu Energy Produced	Remarks
Energy				
Fuel	0.722 × 10^{12} Btu*	0.604 × 10^{15} J*	17.657 × 10^9 Btu	Fuel for 19 wells
Operation and maintenance	35.3 × 10^9 Btu	3.73 × 10^{12} J	1.091 × 10^9 Btu	
Water				
Drilling mud water	0.241 acre-ft* (2.49 × 10^3 bbl)*	0.297 × 10^6 l*	7.43 × 10^{-3} acre-ft (76.8 bbl)*	Fresh or salt water for 19 wells; assumed 31.5 gal/bbl
Fresh water for workers	1.61 acre-ft (16.7 × 10^3 bbl)	1.99 × 10^6 l	49.8 × 10^{-3} acre-ft (515.3 bbl)	Assumed 31.5 gal/bbl
	Total Usage			
Construction Materials		Not Determined		
Land				
Water surface area	2.01 × 10^3 acres	814 ha	62.2 acres	If 1-mi fishing buffer included in permit
Personnel				
Construction and drilling (1½ yr)	45.0-65.1 workers		1.39-2.01 workers	
Operation and maintenance	15.9 workers		0.49 worker	

*Total values during the 1½-yr drilling period.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility	(1978 $)		
Construction (1½ yr)	$56.0 × 10^6 total	$1.73 × 10^6 total	Exploration costs not included; includes platform construction plus drilling costs
Operation and maintenance	$2.05 × 10^6/yr	$0.0634 × 10^6/yr	

OFFSHORE GAS EXTRACTION – LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Oxides of nitrogen	4.92 tons	4.47 tonnes	0.1519 ton	Air pollutants during production
Carbon monoxide	2.03 tons	1.84 tonnes	0.0627 ton	
Hydrocarbons (exhaust)	0.29 ton	0.26 tonne	9.0×10^{-3} ton	
Oxides of sulfur	10×10^{-3} ton	9×10^{-3} tonne	0.3×10^{-3} ton	
Particulates		Not Determined		
Water Pollutants				
Cadmium	0.203 ton	0.185 tonne	629×10^{-3} ton	
Cyanide	0.030 ton	0.027 tonne	0.93×10^{-3} ton	
Mercury	2×10^{-3} ton	1.5×10^{-3} tonne	0.05×10^{-3} ton	
Total organic carbon	1.24×10^3 tons	1.12×10^3 tonnes	38.2 tons	
Total suspended solids	220 tons	200 tonnes	6.8 tons	
Total dissolved solids	330×10^3 tons	300×10^3 tonnes	10.2×10^3 tons	
Solid Wastes				
Drill cuttings	26.6×10^3 tons*	24.1×10^3 tonnes*	820.22 tons	9600-ft well
Drilling muds	4.67×10^3 tons*	4.24×10^3 tonnes*	144.09 tons	

*Solid waste values are total values during the 1½-yr drilling period.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Natural gas	32.4×10^9 ft^3	0.92×10^9 m^3	1×10^9 ft^3	1×10^3 Btu/ft^3

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths*	0.10	3.2×10^{-3}	
Injuries*	0.16	4.9×10^{-3}	

*Sum of injuries and fatalities between 1970–1977, due to blowouts, fire and explosions, and miscellaneous accidents occurring during exploration, development, and production.

BEST DOCUMENT AVAILABLE

NATURAL GAS PURIFICATION

REFERENCE ENERGY SYSTEM

Raw natural gas contains gases and liquids such as water, hydrogen sulfide, carbon dioxide, nitrogen, and various hydrocarbons that have to be removed before the natural gas can be placed in the transmission line. The purification process incorporates dehydration and desulfurization processes, carbon dioxide removal, and natural gas liquids separation to provide a suitable product. Major equipment consists of contactors, stills, reboilers, heaters, condensers, pumps and compressors, and auxiliary hardware.

FACILITY OPERATING PARAMETERS

Size:	250×10^6 ft^3/day gas purification plant (heat content = 1000 Btu/ft^3)
Annual Capacity Factor:	90% (328 days/yr operation)
Annual Energy Production:	82×10^{12} Btu
Efficiency:	87–92%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Sour (acid) gas	91.8×10^9 ft^3	2.60×10^9 m^3	1.12×10^9 ft^3	Assumed 89.5% efficiency, heat content = 1.0×10^3 Btu/ft^3
Energy		Not Determined		Auxiliary energy requirements are process and feed material specific
Processing Materials		Not Determined		
Water				
Boiler make-up	410 acre-ft	506×10^6 l	5.0 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land	22.6 acres	9.12 ha	0.275 acre	
Personnel				
Construction		Not Determined		
Operation and maintenance		↓		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	Not Determined		
Operation and maintenance	↓		
Environmental Controls	Not Determined		Vent gas from Claus (sulfur recovery) plant may require tail gas cleanup (depends on level of cleanup)

NATURAL GAS PURIFICATION

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	13.3 tons	12.0 tonnes	0.162 ton	
Oxides of nitrogen	3.35×10^3 tons	3.04×10^3 tonnes	40.9 tons	
Sulfur dioxide	0.443 ton	0.40 tonne	5.4×10^{-3} ton	
Hydrocarbons	29.5 tons	27 tonnes	0.36 ton	
Carbon monoxide	0.295 ton	0.27 tonne	3.6×10^{-3} ton	
Aldehydes	2.21 tons	2.01 tonnes	0.027 ton	
Water Pollutants				
Condensate stripper bottoms disposal are of environmental concern				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Clean natural gas	82×10^9 ft^3	2.32×10^9 m^3	1×10^9 ft^3	Assumed 89.5% efficiency, heat content = 1.0×10^3 Btu/ft^3
Byproducts				
Sulfur		Not Determined		
Natural gas liquids		↑		Propane, butane, and other "sweet" hydrocarbons

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

UNDERGROUND NATURAL GAS STORAGE

REFERENCE ENERGY SYSTEM

The underground natural gas storage system consists of 50 wells drilled in a depleted gas field of 5000 acres. The system is charged annually in the summer, and gas is withdrawn in the winter. Working capacity (annual deliverability) is 60 × 10^9 scf and 2 × 10^9 scf is used as fuel or lost per year. Additional facilities include compressors, metering facilities, scrubbing and dehydration equipment, and 30 mi of 30-in. connecting pipeline.

FACILITY OPERATING PARAMETERS

Size:	60 × 10^9 scf (annual deliverability)
Annual Capacity Factor:	Not determined
Annual Energy Production:	61.2 × 10^{12} Btu (natural gas stored)
Efficiency:	96.77%
Lifetime:	50 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Natural gas stored	61 × 10^9 scf	1.7 × 10^9 m^3	1.0 × 10^9 scf	
Energy				
Field use in compressors	1.5 × 10^9 scf	42 × 10^6 m^3	24 × 10^6 scf	
Lost	0.6 × 10^9 scf	20 × 10^6 m^3	9 × 10^6 scf	
	Total Usage			
Construction Materials				
Concrete (including cement)	1.92 × 10^3 tons	1.74 × 10^3 tonnes	31.314 tons	
Bentonite (in drilling mud)	350 tons	318 tonnes	5.719 tons	
Barite (in drilling mud)	200 tons	182 tonnes	3.268 tons	
Steel	27.1 × 10^3 tons	24.6 × 10^3 tonnes	442.569 tons	
Copper	84.6 tons	76.8 tonnes	1.383 tons	
Aluminum	29.2 tons	26.5 tonnes	0.477 ton	
Manganese	203 tons	185 tonnes	3.323 tons	
Chrome	51.5 tons	46.7 tonnes	0.841 ton	
Nickel	4.3 tons	3.9 tonnes	0.071 ton	
Cast iron	370 tons	336 tonnes	6.049 tons	
Land				
Surface land occupied	20.0 acres	8.10 ha	0.327 acres	
Underground lease	5.00 × 10^3 acres	2.02 × 10^3 ha	81.700 acres	
Total	5.02 × 10^3 acres	2.03 × 10^3 ha	82.027 acres	
Personnel				
Construction (3 yr)	879 workers		14.36 workers	
Operation and maintenance	2.6 workers		0.043 worker	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (3 yr)	\$95.0 × 10^6 total	\$1.552 × 10^6 total	
Operation and maintenance	\$933 × 10^3/yr	\$15.24 × 10^3/yr	
Environmental Controls			
	Not Determined		

UNDERGROUND NATURAL GAS STORAGE

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates		Not Determined		Information not available
Oxides of sulfur	11.6 tons	10.5 tonnes	0.1889 ton	
Oxides of nitrogen	8.38×10^3 tons	7.61×10^3 tonnes	136.98 tons	
Hydrocarbons	578 tons	525 tonnes	9.447 tons	
Carbon monoxide	240 tons	218 tonnes	3.915 tons	

Water Pollutants

Sediments in streams may temporarily increase during construction; defective gas well casings could potentially result in contamination of local aquifers

Solid Wastes

Negligible waste produced

Noise Pollution

Noise during construction would be limited to compressor stations and would probably be less than 60 dBA at property boundary

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Natural gas stored (net)	60.0×10^9 scf	1.70×10^9 m^3	980.392×10^6 scf	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined
(Information not available)

UNCONVENTIONAL GAS RECOVERY

REFERENCE ENERGY SYSTEM

One 9000-ft deep well, located in an arid western U.S. setting, employing four stages of hydraulic fracturing. Locale consists of steppes and buttes, sage brush, deer, antelope, and small game in area. "Tight sands" gas deposits are found at depths from 5000 ft to 15,000 ft located in Montana, North and South Dakota, Idaho, Wyoming, Utah, Colorado, Nebraska, New Mexico, Texas, Oklahoma, Arkansas, and Louisiana.[a,b] Conventional drilling is followed by massive hydraulic fracturing, which may be repeated three times over the 30-yr life of the well.

FACILITY OPERATING PARAMETERS

Size:	One well with 0.3 × 10^6 ft^3/day gas output (average)
Annual Capacity Factor:	60%*
Annual Energy Production:	0.066 × 10^{12} Btu
Lifetime:	30+ yr

*Due to seasonal (summer) low demand, wells are shut in an average of 40% of the time.

RESOURCES USED

	Quantities Used			
	Reference Energy System Total Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Energy				
Drilling	33.6 × 10^9 Btu	35.4 × 10^{12} J	509 × 10^9 Btu	
Fracturing	1.32 × 10^9 Btu	1.39 × 10^{12} J	20 × 10^9 Btu	3 stimulations in 30-yr lifetime
Maintenance		Not Determined		
Processing Materials				
Production tubing	1 mi	1.61 km	15.6 mi	2-in. outside dia.
Water				
Drilling and fracturing	3.07-6.14 acre-ft	3.79 × 10^6-7.58 × 10^6 l	46.5-93.0 acre-ft	0.921 acre-ft/fracture
Construction Materials				
Sand	375 tons	340 tonnes	5.68 × 10^3 tons	
Potassium chloride	37.5 tons	34.0 tonnes	568 tons	
Conductor casing	50 ft	15 m	760 ft	20-in. outside dia.
Surface casing	1.00 × 10^3 ft	305 m	15.2 × 10^3 ft	12-in. outside dia.
Production casing	9.00 × 10^3 ft	2.74 × 10^3 m	136 × 10^3 ft	9-in. outside dia.
Condensate storage tank	1 unit	1 unit	15.2 units	300-bbl capacity/ unit
Oil-gas-water separator	1 unit	1 unit	15.2 units	
Tubing (well head to separator)	50 ft	15 m	760 ft	2-in. outside dia.
"Christmas tree assembly"	1 unit	1 unit	15.2 units	3 valves, pressure gauge, tubing as needed
Land				
Temporary disturbance	4-5 acres	1.6-2.0 ha	61-76 acres	
Road access	2.5 acres	1.0 ha	38 acres	2-4 mo
Personnel				
Construction (70 days drilling)	15 workers/crew		44 workers	
Operation and maintenance	2 workers		30 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
Construction	Not Determined		
Operation and maintenance	\$7.00 × 10^3/yr	\$0.106 × 10^6/yr	
Environmental Controls			
Lined fluid pits	Not Determined		
Noise reduction and containment	↓		
Water sprayed on temporary roads to reduce dust	↓		
Blowout preventer	\$0.1 × 10^6/total	\$1.5 × 10^6/total	15 × 10^3 psi reuseable unit

UNCONVENTIONAL GAS RECOVERY

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Total Levels		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants*				
Dust		Not Determined		
Diesel emissions/drilling				
• Oxides of sulfur	18.9 tons	17.2 tonnes	286 tons	Based on extrapolation from one diesel engine (1100 hp)[c]
• Oxides of nitrogen	25.8 tons	23.4 tonnes	391 tons	
• Hydrocarbons	14.8 tons	13.4 tonnes	224 tons	
• Carbon monoxide	22.8 tons	20.7 tonnes	345 tons	
• Particulates	7.25 tons	6.58 tonnes	110 tons	
• Aldehydes	1.2 tons	1.1 tonnes	18 tons	
Diesel emissions/fracturing				
• Oxides of sulfur	0.743 ton	0.674 tonne	11.2 tons	
• Oxides of nitrogen	1.04 tons	0.944 tonne	15.8 tons	
• Hydrocarbons	0.582 ton	0.528 tonne	8.82 tons	
• Carbon monoxide	0.893 ton	0.811 tonne	13.5 tons	
• Particulates	0.286 ton	0.260 tonne	4.33 tons	
• Aldehydes	0.046 ton	0.042 tonne	0.70 ton	
Water Pollutants*				
Erosion of disturbed soils (minimal controls)				
Solid Wastes*				
Drilling mud waste (13 parts/gal mud)	250 tons	227 tonnes	3.79×10^3 tons	No current regulations
Well residue	438 tons	398 tonnes	6.63×10^3 tons	
Noise Pollution*,**				
Drilling phase		~ 80-90 dBA		
Fracturing (3-4 days)		~ 96 dBA		

*Pollutants produced in drilling and fracturing period (70 days). No residual effects; all are temporary and end with construction phase.

**Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Natural gas	65.7×10^6 scf (65.7×10^9 Btu)	1.86×10^6 m^3 (69.3×10^{12} J)	995×10^6 scf (995×10^9 Btu)	1×10^3 Btu/scf
Byproducts				
Condensate (wet gas or casing head gas)	6.2×10^3 bbl (35×10^9 Btu)	980×10^3 l (37.0×10^{12} J)	94×10^3 bbl (530×10^9 Btu)	200 bbl/wk

OCCUPATIONAL SAFETY AND HEATLH[d,e]

	Reference Energy System Annual (Industry 1974-1979)	Per 10^{12} Btu Energy Produced	Remarks
Deaths			
Exploration and production	0.1 per 1000 workers	Not Determined	
Injuries			
Exploration and production (1978)	38 per 1000 workers	Not Determined	
Drilling	279 per 1000 workers	↓	

(Continued on next page)

UNCONVENTIONAL GAS RECOVERY

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[b] E. F. Riedel, C. E. Cowan, and T. J. McLaughlin, An Assessment of Environmental Health and Safety Issues Associated with the Commercialization of Unconventional Gas Recovery: Tight Western Sands, PNL-3391, February 1980.

[c] Ibid., pp. 5-6.

[d] American Petroleum Institute, Review of Fatal Injuries in the Petroleum Industry for 1974-1979, five-volume series, p. 1 of each volume.

[e] American Petroleum Institute, Summary of Occupational Injuries and Illnesses in the Petroleum Industry, 1974-1979, five-volume series, p. 2 of each volume.

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SOLAR TECHNOLOGIES

133

BEST DOCUMENT AVAILABLE

RESIDENTIAL/COMMERCIAL HOT WATER HEATING – ACTIVE SYSTEM

REFERENCE ENERGY SYSTEM

Denver, Colorado, was selected as the site for the reference residential system, and Indianapolis, Indiana, was selected for the reference commercial hot water system. The design of both systems is the same: solar energy is absorbed by an array of flat-plate collectors and transferred to a storage tank by a water/glycol alcohol solution. Cold make-up water is heated in the solar storage tank and delivered to the auxiliary hot water tank upon demand.

FACILITY OPERATING PARAMETERS

Size:	Residential – 50-ft^2 collector area with 90 gal of storage Commercial – 500-ft^2 collector area with 900 gal of storage Systems provide 75% of reference loads
Annual Capacity Factor:	Not determined
Annual Energy Production: (location specific)	Residential – 7.0 × 10^6 Btu Commercial – 70.0 × 10^6 Btu
Efficiency:	22%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks*
	English Units	Metric Units		
Feed Materials				
Solar radiation	32.3×10^6 Btu	34.1×10^9 J	4.61×10^{12} Btu	R
	323×10^6 Btu	341×10^9 J	4.61×10^{12} Btu	C
Energy				
Auxiliary	2.3×10^6 Btu	2.5×10^9 J	330×10^9 Btu	R
	23×10^6 Btu	25×10^9 J	330×10^9 Btu	C
Ancillary	700×10^3 Btu	740×10^6 J	100×10^9 Btu	R
	7.0×10^6 Btu	7.4×10^9 J	100×10^9 Btu	C
Processing Materials				
Coolant replacement (50% water)**	5 gal	19 l	720×10^3 gal	R
	14 gal	53 l	200×10^3 gal	C
Water***				
Coolant replacement**	2.5 gal	9.3 l	360×10^3 gal	R
	7.0 gal	27 l	1.0×10^6 gal	C
	Total Usage			
Construction Materials				
Steel	70×10^{-3} ton	64×10^{-3} tonne	10×10^3 tons	R
	400×10^{-3} ton	380×10^{-3} tonne	57×10^3 tons	C
Glass	40×10^{-3} ton	36×10^{-3} tonne	5.7×10^3 tons	R
	400×10^{-3} ton	360×10^{-3} tonne	57×10^3 tons	C
Fiberglass	29×10^{-3} ton	26×10^{-3} tonne	4.1×10^3 tons	R
	240×10^{-3} ton	218×10^{-3} tonne	34×10^3 tons	C
Copper	15×10^{-3} ton	13×10^{-3} tonne	2.1×10^3 tons	R
	84×10^{-3} ton	73×10^{-3} tonne	12×10^3 tons	C
Coolant (50% glycol)	14 gal	53 l	2.0×10^6 gal	R
	40 gal	150 l	570×10^3 gal	C
Aluminum	55×10^{-3} ton	50×10^{-3} tonne	7.9×10^3 tons	R
	550×10^{-3} ton	500×10^{-3} tonne	79×10^3 tons	C
Land				
		Negligible		
Personnel				
Construction	0.018 worker		2.5×10^3 workers	
Operation and maintenance		Not Determined		

*R = Residential
C = Commercial

**Replacement every third year.

***If the collectors were washed, significantly more water would be required; however, washing is not normally done.

RESIDENTIAL/COMMERCIAL HOT WATER HEATING – ACTIVE SYSTEM

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks*
Facility			
	(1980 $)		
Construction	$2,250	$320 × 10^6 total	R
	$22,500	$320 × 10^6 total	C
Operation and maintenance	$22.50	$3.2 × 10^6/yr	R
	$225	$3.2 × 10^6/yr	C

*R = Residential
C = Commercial

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks*
Water Pollutants				
Chemical oxygen demand**	0.05 lb	0.02 kg	3.75 tons	R
	0.22 lb	0.10 kg	1.55 tons	C
Solid Wastes				
No annual residuals; however, upon decommissioning, the glass, fiberglass, and coolant must be disposed of				

*R = Residential
C = Commercial
**Assumes ultimate disposal of all working fluid in water.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks*
Primary				
Thermal energy	7.0×10^6 Btu	7.4×10^9 J	1.0×10^{12} Btu	R
	70×10^6 Btu	74×10^9 J	1.0×10^{12} Btu	C
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, the steel, copper, and aluminum may be economically recoverable				

*R = Residential
C = Commercial

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths/Injuries			
Potential safety hazards exist due to accidental collector overheating and fire	Not Determined		

RESIDENTIAL/COMMERCIAL HEATING – ACTIVE SYSTEM

REFERENCE ENERGY SYSTEM

A typical residence in Denver, Colorado, was selected as the reference system. Solar energy is absorbed by an array of flat-plate solar collectors and transferred by a water and glycol alcohol solution to a storage tank. The stored solar energy is then pumped upon demand through a heat exchanger to provide space heating.

FACILITY OPERATING PARAMETERS

Size:	500-ft^2 collector area, 900 gal storage, provides 75% of the load of the reference house
Annual Capacity Factor:	Not determined
Annual Energy Production: (location specific)	47.5 × 10^6 Btu*
Efficiency:	30%
Lifetime:	20 yr

*Assumes a 6-month heating season

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Solar radiation	158 × 10^6 Btu	167 × 10^9 J	3.32 × 10^{12} Btu	
Energy				
Auxiliary	15.8 × 10^6 Btu	16.7 × 10^9 J	332 × 10^9 Btu	To meet load
Ancillary	4.3 × 10^6 Btu	4.5 × 10^9 J	90 × 10^9 Btu	collector and distribution pumps
Processing Materials				
Coolant (50% water, 50% glycol)	14 gal	53 l	280 × 10^3 gal	Assumes replacement of coolant every 3 yr
Water**	7 gal	27 l	140 × 10^3 gal	
	Total Usage			
Construction Materials				
Steel	0.40 ton	0.36 tonne	8.4 × 10^3 tons	
Glass	0.40 ton	0.36 tonne	8.4 × 10^3 tons	
Fiberglass	0.25 ton	0.22 tonne	5.2 × 10^3 tons	
Copper	80 × 10^{-3} ton	73 × 10^{-3} tonne	1.7 × 10^3 tons	
Coolant (50% glycol)	40 gal	150 l	840 × 10^3 gal	
Aluminum	0.55 ton	0.50 tonne	11 × 10^3 tons	
Land		Negligible		
Personnel				
Construction		Not Determined		
Operation and maintenance		Not Determined		

**If the collectors were washed, significantly more water would be required; however, washing is not normally done.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction (0.3 yr)	$22,500	$473 × 10^6 total	
Operation and maintenance	$225	$4.7 × 10^6/yr	
Environmental Controls	Not Determined		

RESIDENTIAL/COMMERCIAL HEATING — ACTIVE SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Water Pollutants				
Chemical oxygen demand	0.15 lb	0.07 kg	1.55 tons	Assumes ultimate disposal of all working fluids in water
Solid Wastes				
No annual residuals; however, upon decommissioning, such materials as glass, fiberglass, and coolant must be disposed of				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Thermal energy	47.5×10^6 Btu	50.1×10^9 J	1.00×10^{12} Btu	
Recoverables/Recyclables				
No annual recoverables are created; however, upon decommissioning, such construction materials as copper, steel, and aluminum may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

RESIDENTIAL HEATING AND COOLING – ACTIVE SYSTEM

REFERENCE ENERGY SYSTEM

A single family residence in Denver, Colorado, was selected as the reference solar heating and cooling system. The system absorbs solar energy with an array of flatplate collectors. A water and glycol alcohol solution transfers the energy to storage through an intermediate heat exchanger. Upon demand, the stored solar energy is pumped through a liquid/air heat exchanger for space heating or to a lithium-bromide absorption chiller for space cooling.

FACILITY OPERATING PARAMETERS

Size:	Collector array – 500 ft^2 Storage – 900 gal Provides 75% of the total reference heating and 70% of the cooling load
Annual Capacity Factor:	Not determined
Annual Energy Production:	70.5 × 10^6 Btu*
Efficiency:*	33% gross, 32% net
Lifetime:	20 yr

*Based on 8 months of operation. Energy output is also highly location specific.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Solar radiation	210 × 10^6 Btu	222 × 10^9 J	3.00 × 10^{12} Btu	For the 8 mo of operation
Energy				
Auxiliary	23.5 × 10^6 Btu	24.8 × 10^9 J	0.33 × 10^{12} Btu	To meet loads to transport and distribute energy
Ancillary (electric motor)	2.4 × 10^3 kWh	2.4 × 10^3 kWh	33.6 × 10^6 kWh	
Processing Materials				
Coolant (50% glycol, 50% water)	14 gal	53 l	200 × 10^3 gal	Assumes replacement of fluid every third year
Water*	7 gal	27 l	99 × 10^3 gal	Replacement of fluid only
	Total Usage			
Construction Materials				
Steel	0.65 ton	0.59 tonne	9.2 × 10^3 tons	
Glass	0.40 ton	0.36 tonne	5.7 × 10^3 tons	
Fiberglass	0.25 ton	0.22 tonne	3.5 × 10^3 tons	
Copper	0.13 ton	0.12 tonne	1.8 × 10^3 tons	
Coolant (50% glycol)	40 gal	150 l	0.57 × 10^6 gal	
Aluminum	0.55 ton	0.50 tonne	7.8 × 10^3 tons	
Land				
		Negligible		
Personnel				
Construction (0.1 yr)	0.142 worker		2.00 × 10^3 workers	
Operation and maintenance		Not Determined		

*If the collectors were washed, significantly more water would be required; however, washing is not normally done.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction (0.1 yr)	$0.0246 × 10^6 total	$350 × 10^6 total	
Operation and maintenance	$0.000025 × 10^6/yr	$0.35 × 10^6/yr	

RESIDENTIAL HEATING AND COOLING — ACTIVE SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Water Pollutants				
Chemical oxygen demand	0.3 lb	0.1 kg	2.0 tons	Assumes ultimate disposal of all working fluids in water
Solid Wastes				
No annual residuals; however, upon decommissioning, the glass, fiberglass, and coolant must be disposed of				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Thermal energy	70.5×10^6 Btu	74.4×10^9 J	1.00×10^{12} Btu	
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, the steel, copper, and aluminum may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths/Injuries			
Potential safety hazards exist due to accidental collector overheating and fire	Not Determined		

RESIDENTIAL/COMMERCIAL HEATING – PASSIVE SYSTEM

REFERENCE ENERGY SYSTEM

Denver, Colorado, was selected as the location of the reference passive heating system. The system functions by absorbing solar radiation on a selectively coated vertical wall. The radiation warms the concrete wall, and that warmth is conducted through the wall and then, by natural convection, into the space. The wall thickness is selected to provide the proper thermal capacitance to even out the absorption/release of thermal energy. Orientation of the wall can range from south to southwest. Two glazings and moveable insulation limit heat losses during periods of low or no sun.

FACILITY OPERATING PARAMETERS

Size:	500 ft^2 aperture, 18-in.-thick concrete wall; provides 75% of reference load
Annual Capacity Factor:	Not determined
Annual Energy Production:	47.5 × 10^6 Btu*
Efficiency:	32%
Lifetime:	20 yr

*Based on a 6-month heating season. Energy output is also highly location specific.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Solar energy	150 × 10^6 Btu	160 × 10^9 J	3.2 × 10^{12} Btu	6-month heating season only
Energy				
Auxiliary	15.8 × 10^6 Btu	16.7 × 10^9 J	330 × 10^9 Btu	To meet heating load
	Total Usage			
Construction Materials				
Concrete	56 tons	51 tonnes	1.2 × 10^6 tons	
Glass	0.8 ton	0.7 tonne	17 × 10^3 tons	
Insulation	100 lb	45 kg	1.1 × 10^3 tons	
Land				
Negligible				
Personnel				
Construction (0.02 yr)	0.04 worker		820 workers	
Operation and maintenance	Not Determined			

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1977 $)		
Construction (0.02 yr)	$6600	$140 × 10^6 total	
Operation and maintenance	Negligible		

RESIDENTIAL/COMMERCIAL HEATING – PASSIVE SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Solid Wastes				
No annual residuals; however, upon decommissioning, the construction materials will need to be disposed of if they are not a structural part of the building				
Thermal Discharge				
Excess heat collected during the summer could be avoided by shading	24.5×10^6 Btu	25.8×10^9 J	0.51×10^{12} Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Thermal energy	47.5×10^6 Btu	50.1×10^9 J	1.00×10^{12} Btu	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths/Injuries			
Should be similar to standard residential construction	Not Determined		

LOW-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

REFERENCE ENERGY SYSTEM

A commercial laundry in Indianapolis, Indiana, was designated as the reference process and location for low-temperature solar industrial process heat. The process temperatures range from 120°F to 212°F.

Solar energy is absorbed by a flatplate collector array and transferred to storage by a heat exchanger. A glycol alcohol solution circulates through the collector to prevent freezing. The heated water is delivered to the load from a solar storage tank, through an auxiliary tank.

FACILITY OPERATING PARAMETERS

Size:	500-ft^2 collector area, 900-gal storage, provides 50% of the reference load
Annual Capacity Factor:	Not determined
Annual Energy Production:	65×10^6 Btu*
Efficiency:	28% (gross), 27% (net)
Lifetime:	20 yr

*Annual energy production and system efficiency will vary with available solar radiation, location, and with daily load schedule.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Solar radiation	231×10^6 Btu	244×10^9 J	3.6×10^{12} Btu	
Energy				
Ancillary (electricity)	2.9×10^3 kWh	2.9×10^3 kWh	45×10^6 kWh	A 50% solar fraction is assumed
Auxiliary	65×10^6 Btu	69×10^9 J	1.0×10^{12} Btu	
Processing Materials				
Coolant (50% glycol and 50% water)	13 gal	51 l	207×10^3 gal	Annual usage for replacement of fluid every 3 yr
Water	12×10^3 gal	45×10^3 l	186×10^3 gal	Used for collector washing if performed; very small quantity used for coolant mixture replacement
	Total Usage			
Construction Materials				
Steel	0.40 ton	0.36 tonne	6.2×10^3 tons	
Glass	0.40 ton	0.36 tonne	6.2×10^3 tons	
Fiberglass	0.25 ton	0.22 tonne	3.8×10^3 tons	
Copper	80×10^{-3} ton	73×10^{-3} tonne	1.2×10^3 tons	
Coolant	40 gal	153 l	620×10^3 gal	
Aluminum	0.55 ton	0.50 tonne	8.5×10^3 tons	
Land				
		Negligible		
Personnel				
Construction (0.3 yr)		Not Determined		
Operation and maintenance		↓		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction (0.3 yr)	$22,500	$346 × 10^6 total	
Operation and maintenance	$225	$3.5 × 10^6/yr	

Environmental Controls

A double wall heat exchanger may be used to increase isolation of the process fluid from the glycol solution should this be desired or required by code

LOW-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Water Pollutants				
Chemical oxygen demand (COD)	0.15 lb	0.07 kg	1.2 tons	Assumes ultimate disposal of all working fluid in water
Use of surfactants, detergents, or other compounds in collector washing water also contributes to COD, but quantitative data are not available, and the COD does not reflect these pollutants				
Solid Wastes				
No annual residuals; however, upon decommissioning, such construction materials as glass, fiberglass, and possibly some portion of the metals must be disposed of				
Thermal Discharge				
Thermal discharges from the collector array, piping, and storage are unavoidable; those losses are a very low-grade heat and are not always detrimental				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Thermal energy	65×10^6 Btu	69×10^9 J	1.0×10^{12} Btu	
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, some fraction of the metals may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MEDIUM-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

REFERENCE ENERGY SYSTEM*

A pulp mill in Madison, Wisconsin, was selected as the reference system. Solar energy is reflected and concentrated (maximum concentration ratio: 50:1) by a 500-ft^2 array of compound parabolic concentrating collectors. The array tracks the altitude of the sun. An aromatic alcohol transfers solar energy from the collector to a pressurized storage tank via a heat exchanger. Upon demand, the hot, pressurized storage water is passed through a throttling valve, flashed to steam and applied to the load. Condensate and make-up water return to storage.

*The reference system has been normalized to a 500-ft^2 collector area. To provide a large percentage of the purchased energy load of a typically sized wood pulp application, a solar array would have to be unrealistically large (634,000 ft^2 for a 50-percent solar fraction on a purchased energy load of 270 × 10^9 (Btu/yr)).

FACILITY OPERATING PARAMETERS

Size:	500-ft^2 collector area 900-gal pressurized storage
Annual Capacity Factor:	Not determined
Annual Energy Production:	65 × 10^6 Btu*
Efficiency:	25% (gross)*
Lifetime:	20 yr

*Annual energy production and system efficiency are dependent on available insolation, geographic location, and daily load schedules.

RESOURCES USED

	Quantities Used*			
	Reference Energy System Annual Usage			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Solar energy	267 × 10^6 Btu	281 × 10^9 J	4.10 × 10^{12} Btu	
Energy				
Ancillary*		Not Determined		
Auxiliary*, **		↓		
Processing Materials				
Coolant	13 gal	51 l	207 × 10^3 gal	For replacement every 3 yr
Water	12 × 10^3 gal	45 × 10^3 l	186 × 10^6 gal	Used for collector washing if performed
	Total Usage			
Construction Materials				
Steel	4.0 tons	3.6 tonnes	62 × 10^3 tons	
Glass	0.40 ton	0.36 tonne	6.2 × 10^3 tons	
Aluminum	0.35 ton	0.32 tonne	5.4 × 10^3 tons	
Fiberglass	0.40 ton	0.36 tonne	6.2 × 10^3 tons	
Coolant (aromatic alcohol)	40 gal	151 l	620 × 10^3 gal	
Copper	80 × 10^{-3} ton	73 × 10^{-3} tonne	1.2 × 10^3 tons	
Land				
Assume 1.3 times collector area for ground-mounted arrays				
Personnel				
Construction		Not Determined		
Operation and maintenance		↓		

*The reference system was normalized to 500-ft^2 collector area. However, a solar fraction is not available, and thus, the corresponding ancillary and auxiliary energy requirements are not known.

**In addition to purchased energy, wood pulp mills typically burn wood residues for energy.

MEDIUM-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction	\$25,000	\$380 × 10^6 total	
Operation and maintenance	\$250	\$3.8 × 10^6/yr	

Environmental Controls

A double-walled heat exchanger may be used to help prevent contamination of one working fluid by another if this is desired

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks

Water Pollutants

The bulk of the chemical oxygen demand would come from detergents in collector washing water and from herbicides used to keep ground-mounted arrays free from weeds and brush

Solid Wastes

No annual solid wastes; however, upon decommissioning, such construction materials as glass, fiberglass, and possibly some portion of the metals must be disposed of

Thermal Discharge

Excessive heat may be discharged as a fail-safe during system malfunction; other heat losses are of low grade and are negligible

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Thermal energy	65 × 10^6 Btu	69 × 10^9 J	1.0 × 10^{12} Btu	

Recoverables/Recyclables

No annual recoverables; however, upon decommissioning, some fraction of the metals may be economically recoverable

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

RESIDENTIAL PHOTOVOLTAIC SYSTEM

REFERENCE ENERGY SYSTEM

Phoenix, Arizona, was designated as the location for the reference residential photovoltaic system. Solar radiation strikes silicon photovoltaic cells contained within roofing shingles. This creates a direct current, which is then transformed to an alternating current by an inverter. The alternating current is then supplied to the house load or returned to the utility grid. The utility grid provides backup power, and there is no onsite storage. (Systems located elsewhere might have different collector areas but would otherwise be very similar. One possible variation would be to use photovoltaic modules composed of solar cells attached to other mounting materials (glass or metal). The energy output of the system is dependent on the net collector area, cell efficiency, and geographic location.)

FACILITY OPERATING PARAMETERS

Size:	904-ft^2 net collector area 8.5 kWp (peak)
Annual Capacity Factor:	30%
Annual Energy Production:	69.4 × 10^6 Btu (20,340 kWh—some returned to utility grid)
Efficiency:	10% (varies with cell temperature and composition)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Solar energy	675 × 10^6 Btu	713 × 10^9 J	9.7 × 10^{12} Btu	
Energy				
Auxiliary	400 kWh	400 kWh	5.8 × 10^6 kWh	Net electrical energy purchased (total delivered from utility minus total returned to utility)
Water				
Negligible (if washing of photovoltaic array is performed, an estimated 500 gal/yr is required)				
	Total Usage			
Construction Materials				
Plastic (Lexan)	1.1 tons	1.0 tonne	16 × 10^3 tons	
Silicon*	35 × 10^{-3} ton	32 × 10^{-3} tonne	500 tons	
Aluminum	1.9 × 10^{-3} ton	1.7 × 10^{-3} tonne	28 tons	
Silver	1.2 × 10^{-3} ton	1.1 × 10^{-3} tonne	17 tons	
Solder (60/40 lead/tin)	9.7 × 10^{-3} ton	8.8 × 10^{-3} tonne	140 tons	
Carbon steel	63 × 10^{-3} ton	57 × 10^{-3} tonne	900 tons	
Silicon steel	190 × 10^{-3} ton	170 × 10^{-3} tonne	2.7 × 10^3 tons	
Copper	67 × 10^{-3} ton	61 × 10^{-3} tonne	960 tons	
Plastics (polyester and phenolic)	3.8 × 10^{-3} ton	3.4 × 10^{-3} tonne	54 tons	
Zinc	350 × 10^{-6} ton	320 × 10^{-6} tonne	5 tons	
Exotics (boron, phosphorus)	590 × 10^{-12} ton	540 × 10^{-12} tonne	8.5 × 10^{-6} ton	
Tantalum pentoxide	154 × 10^{-6} ton	140 × 10^{-6} tonne	2.2 tons	
Personnel				
Construction (0.04 yr)	0.04 worker		575 workers	
Operation and maintenance		Not Determined		

*Silicon is the most common material used for solar cells. However, alternate materials such as cadmium sulfide or gallium arsenide are available.

RESIDENTIAL PHOTOVOLTAIC SYSTEM

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
		(1980 $)*	
Construction (0.04 yr)	$\$11.0 \times 10^3$ - 18.0×10^3 total	$\$159 \times 10^6$ - 254×10^6 total	
Operation and maintenance	Not Determined		

*These costs reflect 1986 Department of Energy price goals (in 1980$). Current prices (in 1980) are significantly higher with an 8.5-kWp system today costing approximately $125,000. Actual costs have been decreasing rapidly.

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
There is a potential for accidental high voltage arcing, which will generate ozone and fumes from burned plastics				
Solid Wastes				
No annual residuals; however, upon decommissioning, such construction materials as plastic, silicon, solder, zinc, and exotics must be disposed of				
Thermal Discharge				
Inverter heat loss	10.4×10^6 Btu	11.0×10^9 J	150×10^9 Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electrical energy	20.3×10^3 kWh	20.3×10^3 kWh	0.297×10^9 kWh	
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, such materials as aluminum, silver, steel, and copper may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths and Injuries			
Manufacturing of photovoltaic cells involves many toxic materials; their handling, storage, and transport involves potential health hazards			

BEST DOCUMENT AVAILABLE

SOLAR PHOTOVOLTAIC POWER PLANT (CENTRAL UTILITY)

REFERENCE ENERGY SYSTEM

A field near Phoenix, Arizona, was designated as the reference location for the solar photovoltaic power plant. Ground-mounted arrays of single-crystal silicon photovoltaic cells generated direct electrical current from incident solar radiation. Glass reflectors on the backside of the support structure concentrate the solar radiation in the ratio of 1.23:1. The arrays are connected to a voltage regulator, an a.c./d.c. inverter, and ultimately to a utility grid. The system is designed without a storage device.*

FACILITY OPERATING PARAMETERS

Size:	109 MW_e (peak watts)*
Annual Capacity Factor:	30%
Annual Energy Production:	0.79×10^{12} Btu $(0.23 \times 10^9$ kWh)
Efficiency:	14% net (16% for cells)
Lifetime:	30 yr

*Photovoltaic power plants in other locations may require different collector areas to attain the same annual energy production. System energy output is highly location dependent. Photovoltaic modules with different semiconductors (i.e., cadmium sulfide, gallium arsenide) glazings, and substrates (i.e., aluminum, plastics) are also possible; they would have different efficiencies, produce different amounts of energy, and have different residuals.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Solar energy	5.7×10^{12} Btu	6.0×10^{15} J	7.2×10^{12} Btu	
Water				
Periodic washing of photovoltaic panels and reflector surfaces may be necessary				
	Total Usage			
Construction Materials				
Support structure				
• Concrete	48.8×10^3 tons	44.4×10^3 tonnes	61.5×10^3 tons	
• Steel	4.6×10^3 tons	4.2×10^3 tonnes	5.8×10^3 tons	
Photovoltaic panels*				
•Glazing (Lexan)		Not Determined		
• Silicon	325 tons	296 tonnes	410 tons	
• Silver	11.7 tons	10.7 tonnes	14.8 tons	
• Tantalum pentoxide	1.5 tons	1.4 tonnes	1.9 tons	
• Exotics (boron and phosphorus)	6.0×10^{-6} ton	5.5×10^{-6} tonne	7.6×10^{-6} ton	
• Aluminum	19 tons	17 tonnes	24 tons	
Inverter				
• Steel		Not Determined		
• Copper		↓		
• Zinc		↓		
• Silicon				
Land	230 acres	93 ha	290 acres	
Personnel				
Construction	850 workers		1.08×10^3 workers	
Operation and maintenance		Not Determined		

*Alternate materials available for solar cells include cadmium sulfide and gallium arsenide.

SOLAR PHOTOVOLTAIC POWER PLANT (CENTRAL UTILITY)

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)*		
Construction	$116 × 10^6 - 170 × 10^6 total	$140 × 10^6 - 200 × 10^6 total	
Operation and maintenance	$1.9 × 10^6/yr	$2.3 × 10^6/yr	

*This represents construction in 1986 (in 1980$); it assumes Department of Energy goals for central power stations at that time.

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
There is a potential for accidental high-voltage arcing, which will generate ozone and fumes from burned plastics				
Water Pollutants				
If the photovoltaic arrays are washed, then the detergents (if any) used may ultimately cause oxygen demand; herbicides, if used, also create oxygen demand				
Solid Wastes				
No annual solid wastes are generated; however, upon decommissioning, such solid wastes as concrete, silicon, and the glazing must be disposed of – depending on the economics and efficiency of the recovery process, it may be possible to recycle the silicon component of the cell				
Thermal Discharge				
Heat loss from inverter	55 × 10^9 Btu	58 × 10^{12} J	69 × 10^9 Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electrical energy	0.23 × 10^9 kWh	0.23 × 10^9 kWh	0.29 × 10^9 kWh	
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, such materials as steel, aluminum, silver, and possibly silicon may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths and Injuries			
Manufacture of photovoltaic cells requires handling, storage, and transportation of potentially hazardous substances; accidents involving such substances may cause injuries; accidental high-voltage arcing or short circuits may result in fires and injuries			

BEST DOCUMENT AVAILABLE

RESIDENTIAL/COMMERCIAL WIND ENERGY CONVERSION SYSTEM

REFERENCE ENERGY SYSTEM

A three-blade, horizontal axis rotor, 25 ft in diameter, intercepts the wind and begins to produce electricity at wind speeds of 8 mph. Maximum rated capacity is attained from 26 mph to 50 mph. Beyond 50 mph, the machine automatically stops rotating to protect itself.

The direct current generated is converted to alternating current and tied directly to the utility grid.

FACILITY OPERATING PARAMETERS

Size:	3 blades, 25 ft in diameter, 15 kWe capacity*
Annual Capacity Factor:	22%
Annual Energy Production:	98.7×10^6 Btu* (29.9×10^3 kWh)
Efficiency:	Varies with wind speed—up to 45%
Lifetime:	30 yr

*Low Wind Regime (12-15 mph at 30-ft elevation). Greater energies delivered when machine is in higher wind regimes.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Wind		Not Determined		Minimum (cut in) wind speed is 8 mph and maximum (cut out) wind speed is 50 mph
Water				
Wind energy conversion systems may use pumped water as a storage medium				
	Total Usage			
Construction Materials				
Concrete	0.60 ton	0.55 tonne	6.1×10^3 tons	
Steel	0.22 ton	0.20 tonne	2.2×10^3 tons	
Copper	4.8×10^{-3} ton	4.4×10^{-3} tonne	48 tons	
Fiberglass		Negligible		
Lead	7.5 tons	6.8 tonnes	76×10^3 tons*	Present only if batteries are used as storage medium
Land				
Tower base	5.2×10^{-3} acre	2.1×10^{-3} ha	52 acres	Does not consider wake
Personnel				
Construction	0.053 worker		530 workers	
Operation and maintenance		Not Determined		

*Unrealistically high; not all systems would use lead-acid batteries, and different types of batteries or other types of storage might be used

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1972 $)		
Construction	\$79,000	$800 × 10^6$ total	
Operation and maintenance	Not Determined		
Environmental Controls			
	Not Determined		

RESIDENTIAL/COMMERCIAL WIND ENERGY CONVERSION SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Solid Wastes				
No annual residuals; however, upon decommissioning, the concrete and fiberglass must be disposed of				
Noise Pollution				
Some problems with low frequency noise have been noted but it is not felt to be significant; sound vibrations are also potential sources of electromagnetic interference				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	28.9×10^3 kWh	28.9×10^3 kWh	0.293×10^9 kWh	
Recoverables/Recyclables				
No annual recoverables; however, when decommissioning, the steel, copper, and lead (if present) may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths			
		Not Determined	
Injuries			
Wind energy conversion systems are characterized by safety hazards associated with mechanical stress in rotor blades and tower; the stresses may result in catastrophic failure of those members			

WIND ENERGY CONVERSION SYSTEM – ELECTRIC UTILITY APPLICATION

REFERENCE ENERGY SYSTEM

Wind energy turns a horizontal axis rotor to produce shaft horsepower. The machine operates at constant speed by varying the pitch of its rotor blades. Design wind speeds for the high-, medium-, and low-wind machines are 18, 15, and 12 mph, respectively. The shaft horsepower is converted to electrical energy and supplied to the utility grid. Compressed-air energy storage is used as an alternative to battery storage.

FACILITY OPERATING PARAMETERS

Size:	1.5×10^3 kWe rated capacity Low wind: 278 ft diameter Med. wind: 219 ft diameter High wind: 190 ft diameter
Annual Capacity Factor:	Low wind: 0.22 Med. wind: 0.33 High wind: 0.39
Annual Energy Production:	Low wind: 10×10^9 Btu (2.92×10^6 kWh) Med. wind: 14.8×10^9 Btu (4.33×10^6 kWh) High wind: 17×10^9 Btu (5.01×10^6 kWh)
Efficiency:	Varies with wind speed – up to 45%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Wind		Not Determined		
Energy				
Ancillary		Not Determined		
Water				
Alternate storage systems, such as pumped hydro, may require significant water usage.				
	Total Usage			
Construction Materials				
Concrete	550 tons	500 tonnes	55.0×10^3 tons	Low wind
	470 tons	420 tonnes	31.5×10^3 tons	Med. wind
	370 tons	340 tonnes	21.4×10^3 tons	High wind
Steel	180 tons	160 tonnes	18.0×10^3 tons	Low wind
	140 tons	130 tonnes	9.4×10^3 tons	Med. wind
	95 tons	90 tonnes	5.5×10^3 tons	High wind
Copper	1.3 tons	1.2 tonnes	130 tons	Same for all sizes
Fiberglass	20 tons	18 tonnes	2.0×10^3 tons	Low wind
	14 tons	13 tonnes	0.94×10^3 tons	Med. wind
	8.5 tons	8 tonnes	490 tons	High wind
Land	0.51 acre	0.2 ha	51 acres	Same for all sizes
Personnel				
Construction (0.3 yr)	1.8 workers		180 workers	Low wind
Operation and maintenance		Not Determined		

WIND ENERGY CONVERSION SYSTEM — ELECTRIC UTILITY APPLICATION

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1981 $)		
Construction (0.3 yr)	$30 × 10^3 total	$3.0 × 10^6 total*	Low wind
Operation and maintenance	Not Determined		

*Estimated cost of a yet-to-be-commercialized 1.5 × 10^3-kWe-rated wind machine.

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks

Air Pollutants

Potential for compressed air storage to become contaminated by underground storage exists (for example, residual hydrocarbons from abandoned gas wells or mines)

Water Pollutants

Potential for aquifer pollution by compressed air storage

Solid Wastes

No annual residuals; however, upon decommissioning, the concrete and fiberglass must be disposed of

Noise Pollution

Some problems with low frequency noise have been noted, but they are not considered to be significant

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	2.9 × 10^6 kWh	2.9 × 10^6 kWh	0.29 × 10^9 kWh	Low wind

Recoverables/Recyclables

No annual recoverables; however, upon decommissioning, the copper and steel may be economically recoverable

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	Not Determined		

Injuries

Wind energy conversion systems are characterized by safety hazards associated with mechanical stresses in rotor blades and tower; the stresses may result in catastrophic failure of those members

SOLAR THERMAL POWER PLANT (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM

The central receiver (on a tower) is surrounded by or adjacent to a field of tracking heliostats, which are automatically steered to reflect direct solar radiation onto the receiver. The energy is transferred from the absorber to a working fluid, which is a heat source for a thermodynamic cycle. This cycle generates electricity, which is fed into the utility grid. A storage system is employed to provide a more constant generating capacity. The Southwestern United States is the location of the reference system.

FACILITY OPERATING PARAMETERS

Size:	100×10^3 kWe plant, 7.45×10^6 ft^2 heliostats
Annual Capacity Factor:	50%
Annual Energy Production: (location specific)	1.5×10^{12} Btu (0.44×10^9 kWh)
Efficiency:	23.4%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Incident solar radiation	6.4 10^{12} Btu	6.8×10^{15} J	4.27×10^{12} Btu	
Energy				
Ancillary		Not Determined		
Processing Materials				
Referencing system assumes water as a working fluid and hydrocarbon oil as a storage fluid; other fluids such as liquid sodium, sodium hydroxide, or eutectic salts may be used				
Water				
Process and maintenance	30.3 acre-ft	37.4×10^6 l	20.2 acre-ft	Boiler make-up and heliostat washing
	Total Usage			
Construction Materials				
Aluminum	2×10^3 - 5×10^3 tons	1.8×10^3 - 4.6×10^3 tonnes	1.3×10^3 - 3.4×10^3 tons	
Concrete	150×10^3 - 250×10^3 tons	140×10^3 - 230×10^3 tonnes	100×10^3 - 170×10^3 tons	
Copper	0.5×10^3 - 1.0×10^3 tons	500×10^3 - 910×10^3 tonnes	340–670 tons	
Exotic metals (chrome and titanium)	110–200 tons	95–180 tonnes	70–130 tons	
Glass	5.0×10^3 - 10×10^3 tons	4.5×10^3 - 9.1×10^3 tonnes	3.3×10^3 - 6.7×10^3 tons	
Insulation	2.0×10^3 - 4×10^3 tons	1.8×10^3 - 3.7×10^3 tonnes	1.3×10^3 - 2.7×10^3 tons	
Plastic	0.5×10^3 - 2×10^3 tons	0.5×10^3 - 1.8×10^3 tonnes	0.3×10^3 - 1.3×10^3 tons	
Silver	1-5.0 tons	0.9–4.5 tonnes	0.7–3.3 tons	
Steel	50×10^3 - 70×10^3 tons	45×10^3 - 64×10^3 tonnes	33×10^3 - 47×10^3 tons	
Land	1×10^3 acres	407 ha	670 acres	
Personnel				
Construction (2-3 yr)	850–1.27×10^3 workers		570–850 workers	
Operation and maintenance	60 workers		40 workers	

SOLAR THERMAL POWER PLANT (CENTRAL FACILITY)

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1972 $)		
Construction (2-3 yr)	$\$95.4 \times 10^6$ total	$\$63.6 \times 10^6$ total	
Operation and maintenance	$\$1.0 \times 10^6 - 1.9 \times 10^6$/yr	$\$0.7 \times 10^6 - 1.3 \times 10^6$/yr	
Environmental Controls			
	Not Determined		

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
No normal releases; potential release of pollutants during fire or system rupture (depends on the composition of the working and storage fluids—could include nitrogen oxides, sodium monoxide/peroxide, and sodium hydroxide mists or dusts)				
Water Pollutants				
Boiler blowdown	29 acre-ft	35×10^6 l	19 acre-ft	
Accidental or emergency releases and periodic system flushings release pollutants, depending on fluids involved; possible pollutants are hydrocarbon oils, corrosion inhibitors (chromate, borate, nitrate, nitrite, sulfate, sulphite, arsenate, benzoate salts, triazole, silicate, and phosphates), pH controllers, bactericides, and glycols; herbicides and chemical dust suppressors may be released during maintenance				
Solid Wastes				
No annual residuals; however, upon decommissioning, such construction materials as concrete, glass, insulation, and plastic must be disposed of				
Thermal Discharge				
Waste heat	2.3×10^{12} Btu	2.4×10^{15} J	1.5×10^{12} Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electrical energy	0.44×10^9 kWh	0.44×10^9 kWh	0.293×10^9 kWh	
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, such materials as aluminum, copper, silver, exotic metals, and steel may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths/Injuries			
Reflection from heliostats and fire or system rupture are potential hazards			

OCEAN THERMAL ENERGY CONVERSION

REFERENCE ENERGY SYSTEM

The reference system uses the ocean temperature differential between the surface and depths of up to 1000 ft to drive a simple Rankine cycle to produce electricity. Ammonia is the working fluid, and titanium shell and tube heat exchangers transmit the thermal energy between the ammonia and seawater. Power is transmitted to shore by either a.c. or d.c. cables, depending on the distance.

FACILITY OPERATING PARAMETERS

Size:	400 MWe at 40° FΔT
Annual Capacity Factor:	73 - 90%
Annual Energy Production:*	8.4×10^{12} - 10.4×10^{12} Btu
Efficiency:	3%
Lifetime:	30 yr (plant amortization)

*8.4×10^{12} Btu used to convert annual values.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Seawater				See Water
Energy				
		Not Determined		
Processing Materials				
Ammonia	10 tons	9.1 tonnes	1.2 tons	Make up for losses
Water				
Warm seawater	8.90×10^6 acre-ft	11.0×10^{12} l	1.06×10^6 acre-ft	
Cold seawater	12×10^6 acre-ft	14×10^{12} l	1.4×10^6 acre-ft	
	Total Usage			
Construction Materials				
Concrete	375×10^3 - 467×10^3 tons	340×10^3 - 424×10^3 tonnes	44.6×10^3 - 55.6×10^3 tons	
Steel	63×10^3 - 77×10^3 tons	57×10^3 - 70×10^3 tonnes	7.5×10^3 - 9.2×10^3 tons	
Titanium	8.2×10^3 - 10×10^3 tons	7.4×10^3 - 9.1×10^3 tonnes	0.98×10^3 - 1.2×10^3 tons	
Copper	4.1×10^3 - 5.0×10^3 tons	3.7×10^3 - 4.5×10^3 tonnes	490-600 tons	
Ammonia	6.4×10^3 - 7.9×10^3 tons	5.8×10^3 - 7.2×10^3 tonnes	760-940 tons	
Lead	1.6×10^3 - 1.9×10^3 tons	1.4×10^3 - 1.7×10^3 tonnes	190-230 tons	
Rubberized nylon	5.0×10^3 - 6.3×10^3 tons	4.5×10^3 - 5.7×10^3 tonnes	600-750 tons	
Land				
Shore station	20 acres	8.2 ha	20 acres	Land does not change with plant size
Personnel				
Construction (5 yr)	4.08×10^3 workers		485 workers	
Operation and maintenance		Not Determined		

OCEAN THERMAL ENERGY CONVERSION

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1972 $)		
Construction (5 yr)	\$540 × 10^6 total	\$64.3 × 10^6 total	
Operation and maintenance	\$37 × 10^6/yr	\$4.4 × 10^6/yr	
Environmental Controls			
	Not Determined		

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Water Pollutants				
Free chlorine	14 × 10^3 - 17 × 10^3 tons	13 × 10^3 - 15 × 10^3 tonnes	1.7 × 10^3 - 2.0 × 10^3 tons	
Ammonia	10 tons	9.1 tonnes	1.2 tons	
Oil and grease		Negligible		
Nutrients		↓		
Metals				

Solid Wastes

No annual residuals; however, upon decommissioning, such construction materials as concrete, rubberized nylon, and possibly some portion of the metals must be disposed of

	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Thermal Discharge				
Thermal energy change (decrease in surface waters)	290 × 10^{12} Btu	310 × 10^{15} J	35 × 10^{12} Btu	

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	2.46 × 10^9 kWh	2.46 × 10^9 kWh	0.293 × 10^9 kWh	

Recoverables/Recyclables

No annual recoverables; however, upon decommissioning, some fractions of the metals and ammonia may be economically recoverable

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

WOOD-FIRED STEAM ELECTRIC PLANT

REFERENCE ENERGY SYSTEM

Steam is produced through the direct combustion of wood in a spreader stoker furnace. The steam is expanded in a turbogenerator to produce electricity.

FACILITY OPERATING PARAMETERS

Size:	62 MWe or 1.48×10^{12} Btu/yr
Annual Capacity Factor:	80%
Annual Energy Production:	1.37×10^{12} Btu (net) (0.401×10^{9} kWh)
Efficiency:	19.7% (net)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Dry wood	365×10^3 tons	330×10^3 tonnes	266×10^3 tons	Dry wood assumed to have an energy content of 9.5×10^3 Btu/lb
Energy				
Electricity	31.5×10^6 kWh	31.5×10^6 kWh	23.0×10^6 kWh	
Processing Materials				
Combustion air	2.95×10^6 ton	2.70×10^6 tonnes	2.15×10^6 tons	
Water	3.37×10^3 acre-ft	4.16×10^9 l	2.46×10^3 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land				
Storage and plant	102 acres	41.4 ha	74.6 acres	
Personnel				
Construction (2 yr)		Not Determined		
Operation and maintenance	33.1 workers		24.2 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility	(1977 $)		
Construction (2 yr)	$58.2 × 10^6 total	$42.5 × 10^6 total	
Operation and maintenance	$16.0 × 10^6/yr	$11.7 × 10^6 yr	
Environmental Controls			
Water treatment plant	$0.370 × 10^6 total	0.270 × 10^6 total	Included in facility construction costs
Flue gases can be cleaned with inertial collectors (cyclones), wet scrubbers, dry scrubbers, baghouses, and electrostatic precipitators, but no specific price information was available for these components			

WOOD-FIRED STEAM ELECTIC PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Sulfur dioxide	740 tons	670 tonnes	540 tons	
Oxides of nitrogen	3.7×10^3 tons	3.4×10^3 tonnes	2.7×10^3 tons	
Particulates (inorganics, unburned hydrocarbons, unburned carbons)		trace		
Water Pollutants				
Aqueous waste	1.78×10^3 acre-ft	2.20×10^9 l	1.30×10^3 acre-ft	
Solid Wastes				
Total solid wastes: ash content, 89%; misc. content, 11%	6.71×10^3 tons	6.09×10^3 tonnes	4.90×10^3 tons	Solids are generally inert, composed of silica and alumina oxides with minor fractions of sodium, magnesium, and potassium; lead is found in very minor quantities
Thermal Discharge				
Flue gas	3.2×10^6 tons	2.9×10^6 tonnes	2.3×10^6 tons	Heat content of gas not available

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity (net)	401×10^6 kWh	401×10^6 kWh	293×10^6 kWh	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths			
Hazards are no different from other fossil fuels except that sander dust is highly combustible and requires the utmost care to prevent explosions			
Injuries			
The logging industry (feedstock collection) is considered to be a high-risk industry			

LOW-BTU GAS FROM PYROLYSIS (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM*

The reference system is a simple operation involving storage, shredding, and then pyrolysis. Corn residues are pyrolyzed at low pressures and relatively high temperature (875°C) to produce 64,000 ft^3/hr of 150 Btu/ft^3 gas. Char and oil are also produced.

*Wheat residues could also be pyrolyzed in essentially the same process to produce a low-Btu (130 Btu/ft^3) gas and char. To produce 7.6×10^{10} Btu/yr of gas, 12,510 wet tons/yr of wheat residues would be required. This would also yield 4.1×10^{10} Btu/yr of char for a net system efficiency of 93 percent. Pollutants, costs, and materials would be very similar.

FACILITY OPERATING PARAMETERS

Size:	Scaled for use on a large farm; consumes 11.8×10^3 tons (wet) of corn per year
Annual Capacity Factor:	90%
Annual Energy Production:*	76×10^9 Btu of gas, 41×10^9 Btu of char
Efficiency:	85% total net 42% for gas only
Lifetime:	10 yr

*The production figure does not include the benefits of shredding, as these data were not available. The shredder can be added with only a nominal energy-use penalty (1.5%). The value 76×10^9 Btu of gas is used to convert annual values.

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Corn residues (dry)	9.3×10^3 tons	8.4×10^3 tonnes	120×10^3 tons	
Corn residues (wet)	11.9×10^3 tons	10.8×10^3 tonnes	157×10^3 tons	20% moisture content
Energy				
Electricity	40.1×10^3 kWh	40.1×10^3 kWh	528×10^3 kWh	
Gasoline	3.30×10^3 gal	12.5×10^3 l	43.4×10^3 gal	
	Total Usage			
Construction Materials		Not Determined		
Land				
Conversion facility	0.25 acre	0.10 ha	3.3 acres	
Corn residue production	2.32×10^3 acres	939 ha	30.5×10^3 acres	
Personnel				
Construction (1 yr)	0.45 worker		6.13 workers	
Operation and maintenance	0.50 worker		6.6 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1977 $)		
Construction (1 yr)	$\$0.160 \times 10^6$ total	$\$2.11 \times 10^6$ total	
Operation and maintenance	$\$0.262 \times 10^6$/yr	$\$3.45 \times 10^6$/yr	
Environmental Controls			
Environmental controls are not required for a plant of this size; particulate control would be necessary for larger plants or for control of cumulative effects of several plants			

LOW-BTU GAS FROM PYROLYSIS (CENTRAL FACILITY)

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Hydrogen sulfide	3.50 tons	3.18 tonnes	46.1 tons	
Oxides of nitrogen	3.96 tons	3.60 tonnes	52.1 tons	
Particulates	2.78 tons	2.53 tonnes	36.6 tons	
Solid Wastes				
None, the char and oil that are produced during pyrolysis are considered to be byproducts because they have a market value				
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Product gas	7.6×10^9 Btu	80×10^{12} J	1.0×10^{12} Btu	Heating value = 150 Btu/ft^3
Byproducts				
Char	1.4×10^3 tons (41.3×10^9 Btu)	1.3×10^3 tonnes (43.6×10^{12} J)	18×10^3 tons (543×10^9 Btu)	Heating value = 14.5×10^3 Btu/lb
Pyrolytic oil		Not Determined		Heating value = 18×10^3 Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MEDIUM-BTU BIOGAS FROM ANAEROBIC DIGESTION (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM

200 million gal/day of municipal sludge is anaerobically digested in two stages, producing 600 Btu/ft^3 gas (primarily methane). The digested sludge is filtered. The resulting filtrate is treated, and the filter cake is disposed of.

FACILITY OPERATING PARAMETERS

Size:	Processes sludge from a city of 2 million people
Annual Capacity Factor:	100%
Annual Energy Production:	0.52×10^{12} Btu (net)
Efficiency:	39%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used: Reference Energy System Annual Usage: English Units	Quantities Used: Reference Energy System Annual Usage: Metric Units	Quantities Used: Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Municipal sludge	73×10^9 gal	280×10^9 l	140×10^9 gal	Input 20.17×10^3 lb/hr solids with 75% volatile
Energy				
Digestors	140×10^9 Btu	148×10^{12} J	270×10^9 Btu	
Filter operation	10.3×10^6 kWh	10.3×10^6 kWh	19.8×10^9 kWh	
Processing Materials				
Ferric chloride		Not Determined		
Lime		↓		
Water				
(see PRODUCTS, Recoverables)				
	Total Usage			
Construction Materials				
Steel	1.1×10^3 tons	1.0×10^3 tonnes	2.1×10^3 tons	
Concrete	15.8×10^3 tons	16.6×10^3 tonnes	30.4×10^3 tons	
Land	5 acres	2 ha	9.6 acres	
Personnel				
Construction	59.4 workers		114 workers	
Operation and maintenance		Not Determined		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1972 $)		
Construction	$4.04 × 10^6 total	$7.77 × 10^6 total	
Operation and maintenance	Not Determined		
Environmental Controls			
Digestor gas may need to be scrubbed due to high hydrogen sulfide levels; the digestor supernatant and filtrate are returned to wastewater treatment plant where environmental controls are applied			

MEDIUM-BTU BIOGAS FROM ANAEROBIC DIGESTION (CENTRAL FACILITY)

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants				
Carbon dioxide	22.4×10^3 tons	20.4×10^3 tonnes	43.1×10^3 tons	
Hydrogen sulfide	36×10^3 - 72×10^3 tons	33×10^3 - 66×10^3 tonnes	69×10^3 - 140×10^3 tons	
Oxides of sulfur	74.5-149 tons	67.7-135 tonnes	143-287 tons	
Oxides of nitrogen	73 tons	66 tonnes	140 tons	
Water Pollutants				
Suspended solids	625 tons	567 tonnes	1.2×10^3 tons	
Biochemical oxygen demand	575 tons	523 tonnes	1.1×10^3 tons	
Solid Wastes				
Arsenic	3.8 tons	3.5 tonnes	7.3 tons	
Cadmium	2.2 tons	2.0 tonnes	4.2 tons	
Chromium	88.5 tons	80.3 tonnes	170 tons	
Copper	88.5 tons	80.3 tonnes	170 tons	
Lead	88.5 tons	80.3 tonnes	170 tons	
Mercury	0.88 ton	0.80 tonne	1.7 tons	
Nickel	18 tons	16 tonnes	35 tons	
Silver	20 tons	18 tonnes	38 tons	
Selenium	2.3 tons	2.1 tonnes	4.4 tons	
Zinc	221 tons	201 tonnes	425 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary				
Gas (net)	0.52×10^{12} Btu	0.55×10^{15} J	1.0×10^{12} Btu	Heat content of gas = 600 Btu/ft^3
Byproducts				
Filter cake (can be incinerated to drive turbines)	51×10^3 tons	46×10^3 tonnes	98×10^3 tons	
Recoverables/Recyclables				
Water	0.112×10^3 acre-ft	138×10^6 l	0.216×10^3 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ETHANOL FROM GRAINS

REFERENCE ENERGY SYSTEM

The alcohol fermentation plant is designed to produce 50 million gal/yr of 99.5 volume percent (199 proof) ethanol from corn, along with distiller's dried grains with solubles, a commercial animal feed. The plant operates as a continuous flow process, except for the fermentation and fungal amylase sections, which are operated batchwise. The only required utility hookup is for electricity. The boiler burns high-sulfur, Illinois No. 6 coal. Waste streams are treated in an environmentally acceptable manner prior to final disposal; a flue gas scrubbing system is employed to remove particulates and sulfur oxide emissions, and wastewater is treated in a two-stage activated sludge treatment facility.

FACILITY OPERATING PARAMETERS

Size:	50 × 10^6 gal/yr
Annual Capacity Factor:	90%
Annual Energy Production:	3.78 × 10^{12} Btu
Efficiency:	68.9%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Corn	544 × 10^3 tons	494 × 10^3 tonnes	144 × 10^3 tons	
Energy				
Coal	97.9 × 10^3 tons	88.7 × 10^3 tonnes	25.9 × 10^3 tons	
Electricity	65.8 × 10^6 kWh	65.8 × 10^6 kWh	17.4 × 10^6 kWh	
Processing Materials				
Yeast	396 tons	360 tonnes	105 tons	
Anhydrous ammonia	3.04 × 10^3 tons	2.76 × 10^3 tonnes	804 tons	
Hydrocarbon solvent	9.03 × 10^3 gal	34.2 × 10^3 l	2.39 × 10^3 gal	
Iodine sterilizing solution	7.92 × 10^3 gal	30.0 × 10^3 l	2.09 × 10^3 gal	
Denaturant (unleaded gasoline)	1.00 × 10^6 gal	3.79 × 10^6 l	264 × 10^3 gal	
Water				
Process water	1.01 × 10^3 acre-ft	1.25 × 10^9 l	268 acre-ft	
Raw water make-up	255 acre-ft	315 × 10^6 l	67.4 acre-ft	
	Total Usage			
Construction Materials				
Carbon steel	10.5 × 10^3 tons	9.53 × 10^3 tonnes	2.78 × 10^3 tons	
Stainless steel	1.13 × 10^3 tons	1.02 × 10^3 tonnes	299 tons	
Aluminum	27.5 tons	25.0 tonnes	7.27 × 10^3 tons	
Concrete	23.3 × 10^3 tons	21.2 × 10^3 tonnes	6.16 × 10^3 tons	
Land	50.0 acres	20.2 ha	13.2 acres	
Personnel				
Construction (2 yr)		Not Determined		
Operation and maintenance	159 workers		42.0 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1983 $)*		
Construction (2 yr)	$83.7 × 10^6 total	$22.1 × 10^6 total	
Operation and maintenance	$73.1 × 10^6/yr	$19.3 × 10^6/yr	
Environmental Controls	$10.9 × 10^6 total	$2.89 × 10^6 total	These costs have been included in the above estimates for total capital investment

*Operating cost estimate for 1983 plant startup.

ETHANOL FROM GRAINS

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Oxides of sulfur	938 tons	852 tonnes	248 tons	1.25×10^3 tons*
Oxides of nitrogen	730 tons	662 tonnes	193 tons	730 tons*
Fly ash	104 tons	94.4 tonnes	27.5 tons	104 tons*
Ethanol	415-1.66×10^3 tons	377-1.51×10^3 tonnes	109-439 tons	
Grain dust	653 tons	593 tonnes	173 tons	
Coal dust		Not Determined		
Process carbon dioxide	170×10^3 tons	154×10^3 tonnes	44.9×10^3 tons	
Hydrocarbons		Trace		
Carbon monoxide		Negligible		
Water Pollutants				
Biochemical oxygen demand	150-213 tons	136-193 tonnes	39.7-56.3 tons	
Suspended solids	150-213 tons	136-193 tonnes	39.7-56.3 tons	
Water flow rate (to river)	1.11×10^3 acre-ft	1.37×10^9 l	295 acre-ft	
Solid Wastes				
Fly ash, bottom ash, and waste from sludge	9.04×10^3 tons	8.21×10^3 tonnes	2.39×10^3 tons	
Collected coal dust		Not Determined		
Grain cleaning wastes		↓		
Thermal Discharge		Not Determined		
Noise Pollution		Not Determined		

*Federal regulatory compliance level.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Ethanol (199 proof)	50×10^6 gal	190×10^6 l	13×10^6 gal	
Byproducts				
Distiller's dark grains	177×10^3 tons	161×10^3 tonnes	46.8×10^3 tons	
Dry ammonium sulfate	31.6 tons	28.7 tonnes	8.36 tons	
Fusel oil*	760 tons	690 tonnes	201 tons	
Recoverables/Recyclables				

*Fusel oils are usually mixed with the grain ethanol product prior to blending with gasoline.

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	8.61×10^{-3}	2.28×10^{-3}	
Injuries	6.84	1.81	

ETHANOL FROM NONWOOD CELLULOSIC WASTES

REFERENCE ENERGY SYSTEM

The Arkansas/Gulf Simultaneous Saccharification and Fermentation process was chosen as the reference system. It employs cellulosic waste material containing about 57 percent cellulose as a feedstock. Typical raw material consists of two-thirds municipal solid waste (MSW) and one-third pumpmill waste (PMW). About 15 percent of the pretreated MSW is sterilized and employed as feedstock in a continuous enzyme production facility, and the remainder is mechanically treated and mixed with incoming PMW to feed the simultaneous saccharification steps. The ethanol is finally recovered to produce either anhydrous-grade (200 proof) or industrial-grade (190 proof) alcohol. Appropriate environmental control technologies are applied to limit residuals within compliance levels.

FACILITY OPERATING PARAMETERS

Size:	50 × 10^6 gal/yr
Annual Capacity Factor:	90%
Annual Energy Production:	3.60 × 10^{12} Btu
Efficiency:	51%
Lifetime:	10 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Municipal solid waste	442 × 10^3 tons	401 × 10^3 tonnes	123 × 10^3 tons	Oven-dry basis
Pulpmill waste	218 × 10^3 tons	198 × 10^3 tonnes	60.6 × 10^3 tons	↓
Energy				
Power	217 × 10^6 kWh	217 × 10^6 kWh	60.3 × 10^6 kWh	
Fuel oil	392 × 10^9 Btu	414 × 10^{12} J	109 × 10^9 Btu	
Processing Materials				
Nutrients and water	110 × 10^3 tons	100 × 10^3 tonnes	30.6 × 10^3 tons	
Water (see Processing Materials)				
	Total Usage			
Construction Materials		Not Determined		
Land	50 acres	20 ha	14 acres	
Personnel				
Construction (3 yr)		Not Determined		
Operation and maintenance	77 workers		21 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1983 $)*		
Construction (3 yr)	$119 × 10^6 total	$33.1 × 10^6 total	
Operation and maintenance	$37.2 × 10^6/yr	$10.3 × 10^6/yr	
Environmental Controls			
Costs associated with environmental control technology such as flue gas scrubber, wastewater treatment, etc., are included in the above estimates			

*Operating cost estimate for 1983 plant startup.

ETHANOL FROM NONWOOD CELLULOSIC WASTES

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Process carbon dioxide	154 × 10^3 tons	140 × 10^3 tonnes	42.7 × 10^3 tons	
Fly ash (particulates)		Not Determined		
Oxides of sulfur		↓		
Oxides of nitrogen				
Ethanol vapor	415-1.66 × 10^3 tons	377-1.51 × 10^3 tonnes	115-451 tons	
Hydrocarbons		Not Determined		
Dust from raw materials handling		↓		
Carbon monoxide				
Water Pollutants				
Biochemical oxygen demand	300-425 tons	272-386 tonnes	83.3-118 tons	
Suspended solids	300-425 tons	272-386 tonnes	83.3-118 tons	
Water flow rate	1.84 × 10^3 - 8.44 × 10^3 acre-ft	2.27 × 10^9 - 10.4 × 10^9 l	0.511 × 10^3 - 2.34 × 10^3 acre-ft	
Solid Wastes				
Ash	39.6 × 10^3 tons	36.0 × 10^3 tonnes	11.0 × 10^3 tons	
Sludge from wastewater treatment	9.9 × 10^3 tons	9.0 × 10^3 tonnes	2.8 × 10^3 tons	
Noncellulosics from raw material processing	310 × 10^3 tons	281 × 10^3 tonnes	86.1 × 10^3 tons	
Thermal Discharge				
		Not Determined		
Noise Pollution				
		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Anhydrous ethanol (200 proof)	24.1 × 10^6 gal	91.2 × 10^6 l	6.69 × 10^6 gal	
Industrial ethanol (190 proof)	24.8 × 10^6 gal	93.9 × 10^6 l	6.89 × 10^6 gal	
Byproducts				
Animal feed molasses	176 × 10^3 tons	160 × 10^3 tonnes	48.9 × 10^3 tons	
Recoverables/Recyclables				
Fuel oils	3.96 × 10^3 tons	3.60 × 10^3 tonnes	1.10 × 10^3 tons	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	4.17 × 10^{-3}	1.16 × 10^{-3}	
Injuries	3.31	0.919	

METHANOL FROM WOOD

REFERENCE ENERGY SYSTEM

Wood feedstock is fed into a gasifier where the heated wood releases synthesis gas in the presence of oxygen. Ash and unconverted carbon are waste products of this process. The synthesis gas then passes through an acid gas removal system prior to entering the cyrogenic separation unit. The methanol is then synthesized and purified into fuel-grade methanol.

FACILITY OPERATING PARAMETERS

Size:	Will support space heating and hot water needs of about 8100 households
Annual Capacity Factor:	90%
Annual Energy Production:	3.62×10^{12} Btu (net)
Efficiency:	57% (net)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Wood (dry)	0.329×10^6 tons	0.298×10^6 tonnes	90.9×10^3 tons	Assumes dry wood at 9.65×10^3 Btu/lb; quantities used would be twice as much for wet wood at 4.825×10^3 Btu/lb
Energy				
Electricity	59.2×10^9 Btu	62.4×10^{12} J	16.4×10^9 Btu	
Processing Materials				
Oxygen	0.166×10^6 tons	0.150×10^6 tonnes	45.9×10^3 tons	
Combustion and dryer air	1.31×10^6 tons	1.19×10^6 tonnes	0.362×10^6 tons	
Water	2.25×10^3 acre-ft	2.78×10^9 l	0.623×10^3 acre-ft	
	Total Usage			
Construction Materials				
		Not Determined		
Land				
Feedstock supply	5.36×10^6 acres	2.17×10^6 ha	1.48×10^6 acres	
Plant site	2.0 acres	0.81 ha	0.55 acre	
Personnel				
Construction (1.4 yr)	176 workers		48.6 workers	
Operation and maintenance	61.1 workers		16.9 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1976 $)		
Construction (1.4 yr)	$88.0 × 10^6 total	$24.3 × 10^6 total	
Operation and maintenance	$23.3 × 10^6/yr	$6.44 × 10^6/yr	

Environmental Controls

An acid gas removal system and a sulfur removal system (Stretford) are used to control emissions

METHANOL FROM WOOD

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Oxides of sulfur		Trace		
Oxides of nitrogen	72.4 tons	65.7 tonnes	20.0 tons	
Particulates		Trace		
Water Pollutants				
Aqueous waste	1.11×10^3 acre-ft	1.37×10^9 l	0.307×10^3 acre-ft	
Solid Wastes				
Ash and unconverted carbon	8.33×10^3 tons	7.56×10^3 tonnes	2.30×10^3 tons	
Thermal Discharge		Not Determined		
Noise Pollution		Not Determined		

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Methanol	3.62×10^{12} Btu	3.82×10^{15} J	1.00×10^{12} Btu	
Byproducts				
Sulfur	395 tons	360 tonnes	109 tons	
Recoverables/Recyclables				
Treated wastewater	0.936×10^3 acre-ft	1.16×10^9 l	0.258×10^3 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MEDIUM-BTU WOOD GASIFICATION SYSTEM (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM

Wood is reduced to uniformly sized chips and fed into an oxygen-blown pyrolytic reactor. Product gas (46% carbon monoxide, 27% hydrogen, 13% carbon dioxide, 8% methane, 5% water) leaves the reactor with a heating value of about 260 Btu/ft^3. It is then scrubbed and precipitated prior to storage.

FACILITY OPERATING PARAMETERS

Size:	Will support space heating and hot water needs of about 8600 households
Annual Capacity Factor:	Not determined
Annual Energy Production:	3.86 × 10^{12} Btu (net)
Efficiency:	73.2% (net)
Lifetime:	25 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Wood chips	310 × 10^3 tons	280 × 10^3 tonnes	80 × 10^3 tons	
Oxygen		Not Determined		
Energy				
Electrical power (estimated)	6.0 × 10^3 kWh	6.0 × 10^3 kWh	1.5 × 10^3 kWh	
Processing Materials				
Gas (for pilot burner in (combustor)		Not Determined ↓		
Cleaning solvent (in electrostatic precipitator)				
Water				
Cooling and scrubbing	0.386 × 10^3 acre-ft	480 × 10^6 l	0.101 × 10^3 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land				
Plant site	8.5 acres	3.4 ha	2.2 acres	
For sustainable wood supply	> 60.0 × 10^3 acres	> 24.3 × 10^3 ha	> 15.5 × 10^3 acres	
Personnel				
Construction (2 yr)	382 workers		99 workers	
Operation and maintenance	49 workers		12.7 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1976 $)		
Construction (2 yr)	$14.7 × 10^6 total	$3.81 × 10^6 total	
Operation and maintenance	$ 7.21 × 10^6/yr	$1.87 × 10^6/yr	

Environmental Controls

The primary impact of a wood gasification system is created by the harvesting of wood rather than the conversion process; the residuals of the conversion process have minimal impact; the slag residue produces no objectionable leachates and is used as a solid fill or roadbed material

MEDIUM-BTU WOOD GASIFICATION SYSTEM (CENTRAL FACILITY)

ENVIRONMENTAL RESIDUALS

	Quantities Released Reference Energy System Annual Levels English Units	Quantities Released Reference Energy System Annual Levels Metric Units	Quantities Released Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Particulates	1.39 tons	1.26 tonnes	0.360 ton	
Tire wear	0.270 ton	0.250 tonne	0.070 ton	
Sulfur dioxide	4.05 tons	3.68 tonnes	1.05 tons	
Carbon monoxide	41.7 tons	37.9 tonnes	10.8 tons	
HCO	6.56 tons	5.96 tonnes	1.71 tons	
Oxides of nitrogen	30.5 tons	27.7 tonnes	7.90 tons	
Aldehydes	0.42 ton	0.38 tonne	0.11 ton	
Organic acids	0.42 ton	0.38 tonne	0.11 ton	
Water Pollutants				
Suspended solids	3.63×10^3 tons	3.30×10^3 tonnes	940 tons	
Biochemical oxygen demand	42.8 tons	38.9 tonnes	11.1 tons	
Chemical oxygen demand	83.5 tons	75.9 tonnes	21.6 tons	
Carbon solvent	21.7 tons	19.7 tonnes	5.62 tons	
Cadmium	0.040 ton	0.036 tonne	0.01 ton	
Chromium	0.015 ton	0.014 tonne	0.004 ton	
Copper	0.027 ton	0.024 tonne	0.007 ton	
Ferric chloride	5.83 tons	5.30 tonnes	1.51 tons	
Ferric sulphate	2.93 tons	2.66 tonnes	0.76 ton	
Mercury	7.0×10^{-3} ton	6.3×10^{-3} tonne	1.8×10^{-3} ton	
Manganese	6.95 tons	6.31 tonnes	1.80 tons	
Nickel	0.039 ton	0.035 tonne	0.010 ton	
Lead	15.2 tons	13.8 tonnes	3.94 tons	
Zinc	29.6 tons	26.9 tonnes	7.67 tons	
Solid Wastes				
Slag/Ash	3.10×10^3 tons	2.81×10^3 tonnes	803 tons	
Antimony	180×10^{-6} ton	163×10^{-6} tonne	47.0×10^{-6} ton	
Arsenic	630×10^{-6} ton	570×10^{-6} tonne	164×10^{-6} ton	
Barium	43.0×10^{-3} ton	39.0×10^{-3} tonne	11.2×10^{-3} ton	
Beryllium	0.32×10^{-3} ton	0.29×10^{-3} tonne	83×10^{-6} ton	
Boron	46×10^{-3} ton	42×10^{-3} tonne	12×10^{-6} ton	
Cadmium	1.97×10^{-3} ton	1.80×10^{-3} tonne	0.51×10^{-3} ton	
Chlorine	6.18 tons	5.61 tonnes	1.60 tons	
Chromium	0.71×10^{-3} ton	0.65×10^{-3} tonne	0.18×10^{-3} ton	
Cobalt	1.47×10^{-3} ton	1.34×10^{-3} tonne	0.38×10^{-3} ton	
Copper	43.2×10^{-3} ton	39.3×10^{-3} tonne	11.2×10^{-3} ton	
Fluorine	1.55×10^{-3} ton	1.41×10^{-3} tonne	0.40×10^{-3} ton	
Lead	8.34×10^{-3} ton	7.57×10^{-3} tonne	2.16×10^{-3} ton	
Manganese	1.97 tons	1.79 tonnes	0.51 ton	
Mercury	0.48×10^{-3} ton	0.44×10^{-3} tonne	0.12×10^{-3} ton	
Nickel	8.34×10^{-3} ton	7.57×10^{-3} tonne	2.16×10^{-3} ton	
Selenium	0.63×10^{-3} ton	0.58×10^{-3} tonne	0.16×10^{-3} ton	
Tin	0.92×10^{-3} ton	0.84×10^{-3} tonne	0.24×10^{-3} ton	
Titanium	3.09×10^{-3} ton	2.80×10^{-3} tonne	0.80×10^{-3} ton	
Vanadium	4.98×10^{-3} ton	4.52×10^{-3} tonne	1.29×10^{-3} ton	
Zinc	0.502 ton	0.456 tonne	0.13 ton	

PRODUCTS

	Quantities Produced Reference Energy System Annual Production English Units	Quantities Produced Reference Energy System Annual Production Metric Units	Quantities Produced Per 10^{12} Btu Energy Produced	Remarks
Primary				
Pyrolysis gas (net)	13.8×10^9 scf	391×10^6 m^3	3.58×10^9 scf	@1 scf = 260 Btu
Heat value of gas (net)	3.86×10^{12} Btu	4.07×10^{15} J	10^{12} Btu	@1 scf = 260 Btu

Recoverables/Recyclables

Oils and tars collected from the gas by the electrostatic precipitator are reburned in the shaft furnace

Water from the condenser is returned to the gas scrubber

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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GEOTHERMAL TECHNOLOGIES

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GEOTHERMAL—VAPOR DOMINATED SYSTEM

REFERENCE ENERGY SYSTEM

Geothermal—vapor dominated (dry steam) system: Unit 16 of Pacific Gas & Electric/Aminoil Company Geysers generating plant in Lake County, California. (This unit is not constructed yet, but represents the latest design.) The unit will produce commercial electricity. Steam from the Geysers field is used to drive turbine-generators and the steam condensate is used for cooling. A Stretford process unit is used to abate hydrogen sulfide, and secondary treatment of the condensate to remove remaining hydrogen sulfide is proposed.

FACILITY OPERATING PARAMETERS

Size:	110 MWe (net)
Annual Capacity Factor:	80%
Annual Energy Production:	2.63×10^{12} Btu
Efficiency:	16%
Lifetime:	30-35 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Steam (enthalpy of steam)	7.23×10^6 tons (17.1×10^{12} Btu)	6.57×10^6 tonnes (18.1×10^{15} J)	2.75×10^6 tons (6.50×10^{12} Btu)	
Processing Materials				
Hydrogen sulfide abatement				
• Sodium hydroxide	134 tons	122 tonnes	51 tons	
• Sodium ammonium polyvanadate	11 tons	10 tonnes	4.3 tons	
• Anthraquinone disulfonic acid	3 tons	3 tonnes	1.2 tons	
• Hydrogen peroxide	700 tons	640 tonnes	270 tons	
Catalyst				
• Ferrous sulfate and hydroxy acetic acid	200 tons	180 tonnes	75 tons	
Water				
Input from steam wells	5.5×10^3 acre-ft	6.8×10^9 l	2.1×10^3 acre-ft	
Discharge to atmosphere	4.4×10^3 acre-ft	5.4×10^9 l	1.7×10^3 acre-ft	
Injected via wells	1.0×10^3 acre-ft	1.4×10^9 l	400 acre-ft	
	Total Usage			
Construction Materials				
Normal turbine-generator (steam materials)	Not Determined			
Land				
Well field	800 acres	320 ha	300 acres	
Plant site	6.4 acres	2.6 ha	2.4 acres	
Personnel				
Construction	1260 man-months		480 man-months	
Operation and maintenance			7 workers	Shared among the plants

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1979 $)		
Construction (4 yr)	$68.2 $\times 10^6$ total	$25.9 $\times 10^6$ total	1979 dollars plus escalation through 1982
Operation and maintenance	$18.5 $\times 10^6$/yr	$7.0 $\times 10^6$/yr	Includes steam costs that are approximately 73% of total operation and maintenance costs
Environmental Controls			
Secondary treatment of hydrogen sulfide	$4.2 $\times 10^6$/yr	$1.6 $\times 10^6$/yr	Stretford system (hydrogen sulfide abatement) costs are included in operation and maintenance costs above

GEOTHERMAL — VAPOR DOMINATED SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
Hydrogen sulfide	25 tons	22 tonnes	9 tons	
Ammonia	214 tons	194 tonnes	81 tons	
Mercury	0.10 ton	0.1 tonne	0.04 ton	
Arsenic	0.03 ton	0.03 tonne	0.01 ton	
Boron	0.2 ton	0.2 tonne	0.07 ton	
Particulates	18 tons	16 tonnes	7 tons	
Methane	19 tons	17 tonnes	7 tons	
Nonmethane hydrocarbons	< 35 tons	< 32 tonnes	< 13 tons	
Carbon dioxide	22×10^3 tons	20×10^3 tonnes	8.3×10^3 tons	
Nitrogen	95 tons	87 tonnes	36 tons	
Radon-222	98 Ci	98 Ci	37 Ci	
Water Pollutants				
None are released except by accidental occurrence				Water not discharged as vapor reinjected into well
Solid Wastes				
Sludges	3.0×10^3 bbl	0.47×10^6 l	1.1×10^3 bbl	Assumed 1 bbl U.S. liquid = 0.11924 m^3
Thermal Discharge				
Cooling tower	14.4×10^{12} Btu	15×10^{15} J	5.5×10^{12} Btu	
Noise Pollution*				
Well drilling		65–120 dBA at 50 ft		Environmental Protection Agency community noise criterion for well drilling is 55 dBA
Construction (of plant) operations		70-90 dBA at 50 ft		
Plant operations (20-30 yr)				Other noise standards are promulgated by state and local authorities
• Jet gas ejector (continuous)		84-117 dBA at 5-10 ft		
• Turbine generator building (continuous)		70 dBA outside		

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	0.771×10^9 kWh	0.771×10^9kWh	0.293×10^9 kWh	
Byproducts				
Sulfur	400 tons	360 tonnes	150 tons	Recovered as a result of Stretford hydrogen sulfide process

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths	None Observed		
Injuries/Disease*	1	0.4 (average)	Range is 0.1-0.7 incidents

*Based on past operating experience with environmental abatement systems that caused dermatoses.

GEOTHERMAL FLASHED STEAM SYSTEM

REFERENCE ENERGY SYSTEM

Hot geothermal fluid is withdrawn from the geothermal reservoir and steam is flashed from the fluid. The remaining fluid is flashed again at a lower pressure. Steam from both flashes is used to power the turbogenerators. Hydrogen sulfide emissions are abated by the Stretford or EIC process. Residual fluid is injected into a subsurface aquifer.

FACILITY OPERATING PARAMETERS

Size:	50 MWe; 1.12 × 10^{12} Btu (net)
Annual Capacity Factor:	75%
Annual Energy Production:	1.12 × 10^{12} Btu
Efficiency:	5-8% overall, turbine cycle efficiency = 17%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used: Reference Energy System Annual Usage: English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Feed Materials				
Geothermal fluid (230°C)	26.0 × 10^6 tons	23.6 × 10^6 tonnes	22.2 × 10^6 tons	
Energy				
Electricity	32.9 × 10^6 kWh	32.9 × 10^6 kWh	29.4 × 10^6 kWh	
Processing Materials				
Hydrogen sulfide abatement				
• Sodium hydroxide	132 tons	120 tonnes	50.2 tons	Data from Geysers
• Sodium ammonium polyvandate	11.0 tons	10.0 tonnes	4.18 tons	
• Anthraquinone disulfonic acid (ADA)	3.20 tons	2.9 tonnes	1.22 tons	
• Hydrogen peroxide	711 tons	645 tonnes	270 tons	
Catalyst				
• Ferrous sulfate and hydroxy acetic acid	193 tons	175 tonnes	734 tons	
Water				
Cooling tower makeup (10% cycle efficiency)	4.23 × 10^3 acre-ft	5.22 × 10^9 l	3.77 × 10^3 acre-ft	
	Total Usage			
Construction Materials		Not Determined		
Land				
Wells (18 wells at 5 acres/well)	90.0 acres	36.5 ha	80.4 acres	
Power plant	5.00-20.0 acres	2.03-8.10 ha	4.46-17.9 acres	
Personnel				
Construction (2 yr)	233 workers (maximum)		208 workers	
Operation and maintenance	67 workers		60 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1980 $)		
Construction costs	$18 × 10^6 - 75 × 10^6 total	$16 × 10^6 - 67 × 10^6 total	
Operation and maintenance	$1 × 10^6 - 3 × 10^6/yr	$0.9 × 10^6 - 2.7 × 10^6/yr	
Environmental Controls			
	(1980 $)		
Stretford process (with surface condensor)	$3.64 × 10^6	$3.25 × 10^6	
EIC process	$4.64 × 10^6	$4.14 × 10^6	

GEOTHERMAL FLASHED STEAM SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units*	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants**				
Hydrogen sulfide	4.41 - 44.1 tons	4.00 - 40.0 tonnes	3.94 - 39.4 tons	
Ammonia	165 - 17,000 tons	150 - 15,400 tonnes	148 - 15,200 tons	
Methane	452 - 4 520 tons	410 - 4 100 tonnes	404 - 4 040 tons	
Carbon dioxide	6 780 - 67,800 tons	6 150 - 61,500 tonnes	6 050 - 60,500 tons	
Arsenic	0.452 - 4.52 tons	0.410 - 4.10 tonnes	0.404 - 4.04 tons	
Boron	11.4 - 114 tons	10.3 - 103 tonnes	10.2 - 102 tons	
Mercury	0 - 2.26 tons	0 - 2.05 tonnes	0 - 2.02 tons	
Radon	10.5 - 16.1 Ci	10.5 - 16.1 Ci	9.38 - 14.4 Ci	
Benzene	109 - 1 200 tons	98.6 - 1 090 tonnes	97.3 - 1 070 tons	
Water Pollutants**				
(These pollutants are not released to surface waters, but are injected into a subsurface aquifer.)				
Total dissolved solids	12.8×10^3 - 128×10^3 tons	11.6×10^3 - 116×10^3 tonnes	11.4×10^3 - 114×10^3 tons	
Chloride	2.26×10^3 - 22.6×10^3 tons	2.05×10^3 - 20.5×10^3 tonnes	2.02×10^3 - 20.2×10^3 tons	
Calcium	226 - 2 260 tons	205 - 2 050 tonnes	202 - 2 020 tons	
Magnesium	22.6 - 226 tons	20.5 - 205 tonnes	20.2 - 202 tons	
Potassium	1.14×10^3 - 11.4×10^3 tons	1.03×10^3 - 10.3×10^3 tonnes	1.02×10^3 - 10.2×10^3 tons	
Aluminum	11.4 - 114 tons	10.3 - 103 tonnes	10.2 - 102 tons	
Iron	0.542 - 5.42 tons	0.492 - 4.92 tonnes	0.484 - 4.84 tons	
Bromide	11.4 - 114 tons	10.3 - 103 tonnes	10.2 - 102 tons	
Manganese	0.217 - 2.17 tons	0.197 - 1.97 tonnes	0.194 - 1.94 tons	
Strontium	11.4 - 114 tons	10.3 - 103 tonnes	10.2 - 102 tons	
Lithium	22.6 - 226 tons	20.5 - 205 tonnes	20.2 - 202 tons	
Cesium	2.26 - 22.6 tons	2.05 - 20.5 tonnes	2.02 - 20.2 tons	
Fluoride	22.6 - 226 tons	20.5 - 205 tonnes	20.2 - 202 tons	
Rubidium	11.4 - 114 tons	10.3 - 103 tonnes	10.2 - 102 tons	
Iodine	2.26 - 22.6 tons	2.05 - 20.5 tonnes	2.02 - 20.2 tons	
Copper	0 - 0.114 tons	0 - 0.103 tonnes	0 - 0.102 tons	
Sulfur	4.52 - 45.2 tons	4.10 - 41.0 tonnes	4.04 - 40.4 tons	
Sulfate	1.14×10^3 - 11.4×10^3 tons	1.03×10^3 - 10.3×10^3 tonnes	1.02×10^3 - 10.2×10^3 tons	
Silica	1.14×10^3 - 11.4×10^3 tons	1.03×10^3 - 10.3×10^3 tonnes	1.02×10^3 - 10.2×10^3 tons	
Sodium	2.26×10^3 - 22.6×10^3 tons	2.05×10^3 - 20.5×10^3 tonnes	2.02×10^3 - 20.2×10^3 tons	
Solid Wastes**				
Drilling mud	1.81×10^3 - 3.92×10^3 ft^3	5.13×10^3 - 11.1×10^3 m^3	1.62×10^3 - 3.50×10^3 ft^3	
Solids (from total dissolved solids)	9.79×10^3 - 97.9×10^3 tons	8.88×10^3 - 88.8×10^3 tonnes	8.74×10^3 - 87.4×10^3 tons	
Iron	22.1 - 221 tons	20.0 - 200 tonnes	19.7 - 197 tons	
Manganese	22.4 - 224 tons	20.3 - 203 tonnes	20.0 - 200 tons	
Copper	0 - 11.1 tons	0 - 10.1 tonnes	0 - 9.91 tons	
Thermal Discharge				
Discharge to the air	17.2×10^{12} Btu	18.1×10^{15} J	15.4×10^{12} Btu	
Noise Pollution***				
Well drilling		75-85 dB(A) at 50 ft		
Operation of construction machinery		70-95 dB(A) at 50 ft		
Plant operation		70-100 dB(A) at 50 ft		

*Basis of other calculations.

**Quantities indicated for air, water, and solid wastes are based on a total flow of 23.6×10^6 tonnes/yr from 18 wells at 1.31×10^6 tonnes/yr per well. Fluid density is assumed to be 1.15 kg/l.

***Noise cannot be expressed in terms of energy produced.

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GEOTHERMAL FLASHED STEAM SYSTEM

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity (net)	329 × 10^6 kWh	329 × 10^6 kWh	294 × 10^6 kWh	
Recoverables/Recyclables				
Sulfur	378-3780 tons	343-3430 tonnes	338-3380 tons	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Injuries/Illnesses	0.404 injuries/illnesses (per 50 MW)	0.361 injuries/illnesses (per 50 MW)	Based on data from Geysers

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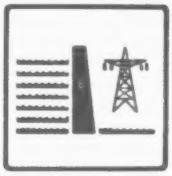

HYDROELECTRIC TECHNOLOGIES

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SMALL HYDROELECTRIC PLANT

REFERENCE ENERGY SYSTEM

Small hydroelectric plants are those with less than 15 MWe of capacity and usually fed by a dam with height not more than 65 ft. Impounding is generally less than 500 acres. Components of a typical system (not an exhaustive listing) include the dam, penstock, hydraulic turbine, generator(s) transformer, and other miscellaneous structures and equipment.

FACILITY OPERATING PARAMETERS

Size:	4 MWe
Annual Capacity Factor:	0.35 for new plants, 0.37 for retrofits
Annual Energy Production:	0.04×10^{12} Btu
Efficiency:	90%
Lifetime:	50 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Water	0.792×10^6 acre-ft	0.977×10^{12} l	19.8×10^6 acre-ft	Kinetic energy of falling or flowing water
Energy Requirements				
Auxiliary		Not Determined		
	Total Usage			
Construction Materials				
		Not Determined		Typical system components are listed in Reference Energy System description
Land				
		Not Determined		
Personnel				
Construction		Not Determined		
Operation and maintenance		↓		

COSTS

	Reference Energy System		Per 10^{12} Btu Energy Produced	Remarks
Facility*				
		(1977 $)		
Construction	$\$7.52 \times 10^6$ total		$\$188 \times 10^6$ total	
		(1972 $)		
Operation and maintenance	$\$0.054 \times 10^6$/yr		$\$1.35 \times 10^6$/yr	
Environmental Controls				
Upstream fish passage facilities can cost between $\$20 \times 10^3$ to $\$98 \times 10^3$/m of elevation				Hydroelectric systems can have water quality and ecological impacts

*Costs are for "installed hydro-power at new dams."

SMALL HYDROELECTRIC PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Water Pollutants				
Thermal stratification in the reservoir can lead to a lowering of dissolved oxygen levels and elevated concentration of ammonia, hydrogen sulfide, iron, and manganese; shoreline erosion may result in increased turbidity				
Thermal Discharge				
Thermal stratification in the reservoir can result in discharged water being warmer in winter and cooler in summer than ambient river water				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	0.012×10^9 kWh	0.012×10^9 kWh	0.293×10^9 kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

LARGE HYDROELECTRIC PLANT

REFERENCE ENERGY SYSTEM

A conventional "run-of-river" hydroelectric plant (i.e., no storage capacity) in which an earth-filled dam (15 × 10^6 yd^3 of earth) is placed across a river to develop water flow capable of driving three 66.7-MWe turbine/generator sets. The plant, categorized as a large hydroelectric plant (greater than 15 MWe) includes the usual system components of dam, spillway, intakes, and a powerhouse consisting of hydraulic structures, turbines, and electrical equipment.

FACILITY OPERATING PARAMETERS

Size:	200 MWe
Annual Capacity Factor:	56%
Annual Energy Production:	3.35 × 10^{12} Btu
Efficiency:	82.6%
Lifetime:	60 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	
	English Units	Metric Units		Remarks
Feed Materials				
Fuel (kinetic energy of water flow)	4.01 × 10^{12} Btu	4.23 × 10^{15} J	1.20 × 10^{12} Btu	
	Total Usage			
Construction Materials				
Concrete	150 × 10^3 tons	136 × 10^3 tonnes	44.8 × 10^3 tons	
Total steel and castings	14.1 × 10^3 tons	12.8 × 10^3 tonnes	4.21 × 10^3 tons	
Copper, brass, and bronze	287 tons	261 tonnes	86 tons	
Aluminum and castings	151 tons	137 tonnes	45 tons	
Manganese	84 tons	76 tonnes	25 tons	
Chromium	20 tons	18 tonnes	6 tons	
Nickel	3.3 tons	3 tonnes	1 ton	
Cast iron	462 tons	419 tonnes	138 tons	
Land				
Acres occupied	397 acres	161 ha	119 acres	
Personnel				
Construction (4.75 yr)	250 workers		75 workers	
Operation and maintenance	16.8 workers		5.02 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (4.75 yr)*	\$131 × 10^6 total	\$39.1 × 10^6 total	
Operation and maintenance	\$0.70 × 10^6/yr	\$0.210 × 10^6/yr	
Environmental Controls			
	Not Determined		Water impoundment may produce minor environmental effects

*Includes cost for estimated land and land rights.

LARGE HYDROELECTRIC PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
No normal releases				
Water Pollutants				
Water quality and quantity may be altered upstream and downstream with potential changes in dissolved gases, temperature, and water levels				
Thermal Release				
No normal releases				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	0.98×10^9 kWh	0.98×10^9 kWh	0.293×10^9 kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

PUMPED STORAGE SYSTEM

REFERENCE ENERGY SYSTEM

A pumped-storage (hydroelectric) plant consisting of four 250-MW pumps and drivers that utilize base load power during off-peak demand for pumping water from a lower to a higher reservoir. The pumping units become turbines driving electrical generators when the stored water is released during periods of high demand. By 1985, pumped storage capacity in the United States is expected to approach 37,300 MWe.

FACILITY OPERATING PARAMETERS

Size:	1000 MWe
Annual Capacity Factor:	13%
Annual Energy Production:	3.89×10^{12} Btu
Efficiency:	70%
Lifetime:	60 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10^{12} Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Off-peak base load electricity	5.56×10^{12} Btu	5.87×10^{15} J	1.43×10^{12} Btu	
	Total Usage			
Construction Materials				
Concrete	587 tons	533 tonnes	151×10^3 tons	
Total steel and castings	62.6×10^3 tons	56.8×10^3 tonnes	16.1×10^3 tons	
Copper, brass, and bronze	743 tons	674 tonnes	191 tons	
Aluminum and castings	486 tons	441 tonnes	125 tons	
Manganese	318 tons	290 tonnes	82 tons	
Chromium	54 tons	49 tonnes	14 tons	
Nickel	12 tons	10 tonnes	3 tons	
Cast iron	1.30×10^3 tons	1.18×10^3 tonnes	335 tons	
Land	2.0×10^3 acres	810 ha	514 acres	
Personnel				
Construction (6.5 yr)	494 workers		127 workers	
Operation and maintenance	33 workers		8.49 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1978 $)		
Construction (6.5 yr)	$\$327 \times 10^6$ total	$\$84.0 \times 10^6$ total*	
Operation and maintenance	$\$1.44 \times 10^6$/yr	$\$0.370 \times 10^6$/yr	
Environmental Controls			
	Not Determined		

*Includes $\$7.8 \times 10^6$ for estimated land and land rights.

PUMPED STORAGE SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Air Pollutants				
No normal releases				
Water Pollutants				
Water quality and quantity may be altered upstream and downstream with potential changes in dissolved gases, temperature, and water levels				
Thermal Discharge				
No normal releases				

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Remarks
Primary				
Electricity	1.14×10^9 kWh	1.14×10^9 kWh	0.293×10^9 kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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GLOSSARY

Anaerobic digestion. The decomposition of organic waste by bacteria that function in the absence of oxygen. Properly controlled, anaerobic digestion will produce a mixture of methane and carbon dioxide and substantially reduce the volume of the waste.

Baghouse. A system for removing particles from a gas stream by means of simple fabric filters shaped like bags. Large sizes and numbers of bags necessitate a separate building (baghouse). Most of the filtering effect is provided by a layer of particles on top of the fabric.

Biochemical oxygen demand (BOD). A measure of the amount of oxygen consumed in the biological processes that break down organic matter in water. The greater the degree of pollution, the greater the BOD.

Blowdown. Portion of fluid in a system (e.g., cooling tower, boiler) removed at regular intervals to prevent accumulation of dissolved and suspended material.

Bottom ash. Noncombustible residues of coal combustion that are collected and removed from the boiler.

Bottoms. Leftovers from distillation, consisting of residue that did not evaporate.

Capacity factor. The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.

Char. Carbonaceous material left over after heating coal or other organic matter.

Chemical oxygen demand (COD). A measure of the amount of oxygen required to oxidize contaminants of water. The COD test is used to determine the degree of pollution in an effluent.

Cogeneration. The near-simultaneous production of electricity and process heat (usually steam) by utilizing the waste heat generated in electricity production.

Cooling tower drift loss. Aerosol of water that is lost to the atmosphere from the cooling towers.

Cooling tower evaporation loss. Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.

Curie (Ci). An amount of radioactive material that decays at a rate of 3.7×10^{10} distintegrations per second.

Cyclone. A mechanical separator that uses swirling air flow to sort particles in a gas stream according to size and density.

Decommissioning. The process of deactivating a facility (e.g. a nuclear power plant) that will not be used again.

Ecosystem. A biological community together with its physical environment.

Electrostatic precipitator (ESP). A device used to remove fine particles (e.g., fly ash) from a gaseous stream. Particles are imparted an electric charge so that they are attracted to an oppositely charged electrode where they accumulate and are then periodically removed.

Fermentation. Originally used to describe the conversion of sugar to alcohol by yeast. The term is now used to describe the enzymatic transformation of organic substances, especially carbohydrates, by the action of microbes.

Flash. Rapid transportation of a heated fluid from liquid to gaseous phase, generally accomplished by sudden reduction in pressure. Superheated geothermal fluid can be partly flashed to yield steam clean enough for use in a turbine.

Flue gas. Gaseous products of combustion. Consists mainly of nitrogen, carbon dioxide, carbon monoxide, oxygen, nitrogen oxides, sulfur dioxide, and fly ash.

Flue gas desulfurization. Removal of sulfur dioxide from flue gas, usually by lime/limestone scrubbing.

Fluidized bed. Freely circulating solid particles in a vessel supported by a flow of gas. In fluidized bed combustion, lime or dolomite can be added as part of the bed material, which reacts with and retains the sulfur compounds released in the combustion process.

Fly ash. Noncombustible residues of coal combustion that are carried out of the boiler in the flue gas, consisting mainly of silica and alumina. Fly ash is removed from flue gas by baghouse filters or electrostatic precipitators.

Fugitive emissions. Unintentional emissions, such as dust blowing from a shale pile.

Fume. Tiny solid particles formed by the condensation of vapors of solid matter.

HEPA filters. Filters used in gaseous waste streams to remove particulate matter.

Kerogen. Organic material contained in oil shale. When heated to about 900°F, kerogen decomposes into hydrocarbons and a carbonaceous residual.

Leaching. Washing out. The natural flow of water through the soil, ore piles, refuse piles, or landfill slowly dissolves and removes soluble substances into groundwater, streams, and rivers. Substances may be removed and transported by percolating water.

Make-up. Water or other fluid regularly added to a system to compensate for losses through process use, evaporation, and blowdown.

Man-rem. A unit for considering the collective radiation dose received by a group of people. One man-rem is equivalent to the amount of radiation dose received by one person exposed to one rem, two persons exposed to one-half rem, etc.

Offgas. Gas produced during a process step, usually as a byproduct or waste.

Overburden. Soil and rock between the surface and a coal seam. The thickness and nature of the overburden is a determinant of the economic feasibility of mining the coal.

Particulates. Finely divided solid material carried an appreciable distance in a gas stream or in the ambient atmosphere. Definitions and size ranges vary widely.

Plant efficiency. Electrical energy out of the plant to the transmission network divided by total heat energy used to produce the electric energy.

Pyrolysis. The process of chemically decomposing a substance by heating it in an oxygen-deficient atmosphere.

Raw shale. Oil shale that has not been retorted.

Recycle water. Water that is collected after process use, treated, and reused at the facility.

Regeneration. Chemical process that permits the reuse of an efficient absorbent or catalyst without discarding it when used up. Chemicals used are called regenerants.

Reinjection. A method to dispose of geothermal fluids that have given up their heat and cannot be easily disposed of on the surface. Reinjection is also used to prevent ground subsidence.

Rem. A unit of radiation dose.

Retort. A closed refractory chamber in which shale is heated and gives off its oil content.

Retorted shale. Shale that has had the oil values extracted and still contains carbon.

Retort gas. High- or low-Btu quality gas that is one of the products of the retorting of oil shale.

Rubblize. The process of breaking up the oil shale deposits, usually with the help of explosives, into rough, angular fragments.

Run-of-mine. Used to describe coal or shale as it comes from the mine before sizing or other preparation.

Scrubber. A device for removing some constituent from a gas stream by spraying the stream with a liquid (usually water) or forcing it through a series of baths.

Shale oil. Oil that results from the retorting of oil shale. It is a liquid multicomponent hydrocarbon mixture resulting from the molecular rearrangement of the kerogen.

Sludge. A general term for wet, semisolid material. Common examples include sewage sludge produced at sewage plants and flue-gas desulfurization (FGD) sludge, which consists of calcium sulfate, calcium sulfite, and water.

Slurry. Solid particles suspended in liquid, such as finely powdered coal suspended in a liquid such as oil or water. Slurries can be pumped and sent through pipelines, greatly easing the difficulties of overload transportation.

Storage battery. Also known as secondary or rechargeable battery. The battery can be recharged after partial or complete discharge by the flow of direct current in a direction opposite to the discharge.

Surface retorting. Extracting oil from oil shale in an aboveground retort.

Syncrude. Shale oil that has been upgraded to remove nitrogen, sulfur, metals, and has little to no bottoms remaining.

Tailings. Leftover material from extraction of ore. They usually contain some unextracted material (e.g., approximately 2 percent of original uranium in uranium tailings).

Trace elements. Chemical elements occurring at low but significant concentrations, either because of their high toxicity or because of uncertainties in the effects of chronic exposure to such elements. Among the most important are certain "heavy metals," e.g., lead, mercury, beryllium, cadmium.

ACRONYMS AND ABBREVIATIONS

AC	alternating current
bbl	barrel
Btu	British thermal unit
CFR	Code of Federal Regulations
Ci	curie
dBA	decibel, adjusted
dia.	diameter
FT	Fischer-Tropsch
ft	foot
gal	gallon
ha	hectare
HEPA	high-efficiency particulate aerosol (filter)
hp	horsepower
in.	inch
J	joule
kg	kilogram
km	kilometer
kV	kilovolt
kWh	kilowatthour
l	liter
lb	pound
m	meter
m^3	cubic meter
max.	maximum
mg	milligram (10^{-3} grams)
mi	mile
mph	miles per hour
MW	megawatt
MWe	megawatt-electric (10^6 watts)
psi	pounds per square inch
ppm	parts per million
ROW	right-of-way
scf	standard cubic feet
V	volt
W	watt
wk	week
yr	year

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APPENDIX. ENVIRONMENTAL CHARACTERIZATION INFORMATION REPORTS

This appendix contains the initial set of four supplementary documents referred to as Environmental Characterization Information Reports (ECIRs), which augment the information summaries provided in this Handbook. The purpose of the ECIR is to present a more explicit treatment of the origin and derivation of the information by providing the reader with an expanded discussion of the data elements of the information summaries (environmental residuals, energy resources used, costs, energy products, and occupational health and safety statistics associated with each reference energy system). Sufficient detail is provided to enable the reader to determine similar or analogous quantitative information for other energy systems, energy process configurations, or varying operational assumptions.

The information contained in an ECIR represents the synthesis of data from a broad range of sources to characterize a "generalized" system configuration for each of the reference energy systems. The reference energy systems or facilities are of a particular size and design, with operational data presented on the basis of annual quantities or total system lifetime quantities, as appropriate. In addition, the data are normalized to 10^{12} (1 trillion) Btu of energy output to facilitate cross-technology comparison and use of the data in computerized data bases and analysis algorithms. The information presented provides a sound basis for general environmental analysis/assessment activities, although actual site-specific designs may vary somewhat from the reference energy systems described.

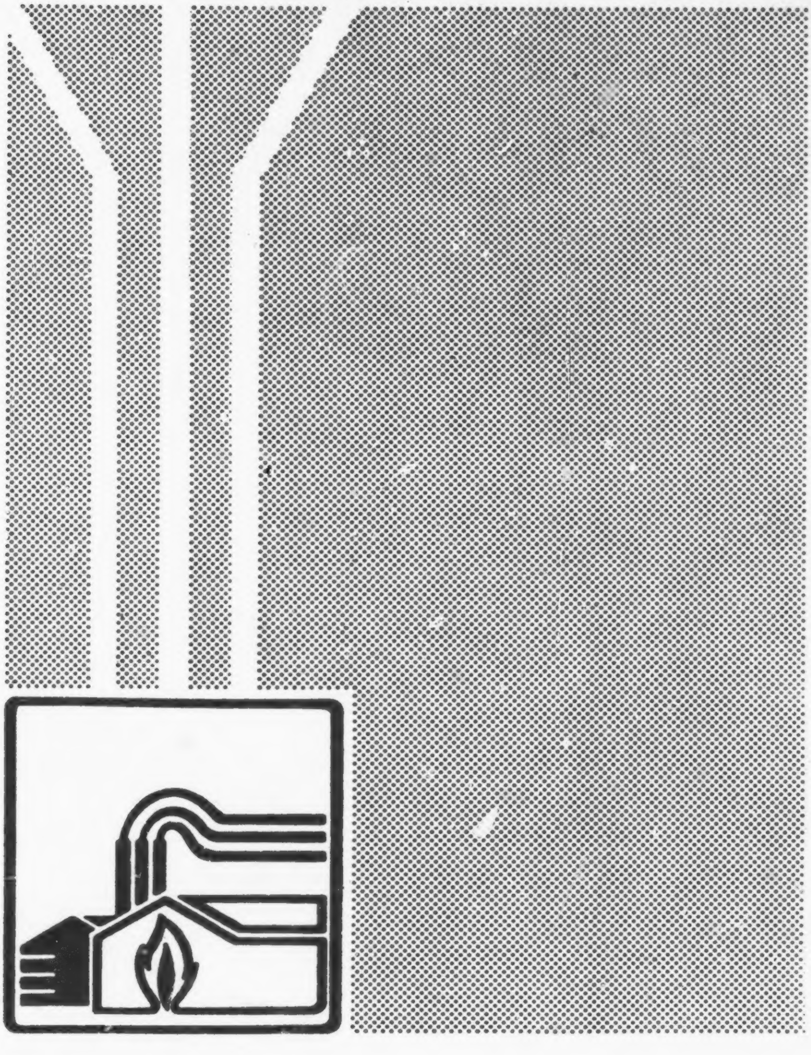
The four ECIRs presented in this appendix are Coal-Fired Power Plant -- Eastern Coal; Coal-Fired Power Plant -- Western Coal; Pressurized Water Reactor Nuclear Power Plant; and, Oil Shale Surface Retorting. These ECIRs and 11 others currently under development will be published as separate reports late in calendar year 1981 and will be available from the National Technical Information Service (NTIS). They include the following:

Boiling Water Reactor Nuclear Power Plant
Commercial Radioactive Waste
Lurgi Process -- Coal Gasification
TOSCO II Shale Retorting
Solvent Refined Coal II
Surface Coal Mining -- Eastern
Surface Coal Mining -- Western
Underground Coal Mining -- Eastern
Ethanol From Grains
Geothermal -- Flash Injection
Indirect Coal Liquefaction Plant

Coal - Fired Power Plant

(Eastern Coal)

Environmental Characterization Information Report



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FOREWORD

This Environmental Characterization Information Report (ECIR) is a synthesis of environmental data and information relevant to a coal-fired power plant that burns eastern coal. It is prototypical of a set of ECIRs that will be developed for a range of fossil, solar, geothermal, nuclear, and conservation energy systems. The ECIRs are designed to have several related purposes: to communicate to all potential users environmental data and information characteristic of an energy system; to present an organized data and information base for application in manual and computer-based analytical systems; and to provide the medium for facilitating development, maintenance, and critical review of the data and information base. The set of ECIRs is designed to replace the general technical backup volumes formerly supplied with "Environmental Data Energy Technology Characterizations," Summary, January 1980.

Responsibility for the contents and development of an ECIR is assigned to individual technology specialists in the Technology Assessments Division. This ECIR was developed under the direction of Mr. William G. Wilson of the Fossil Energy Program staff. In this endeavor, we also draw upon the technical support and assistance of qualified external experts familiar with the energy systems. Technical comments regarding this ECIR should be directed to Mr. William G. Wilson, Project Officer, (301) 353-4414. Suggestions or recommendations for improving the ECIR concept should be addressed to me.

Dario R. Monti
Director, Technology Assessments
Division
Office of Technology Impacts

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I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Coal-Fired Power Plants (Eastern Coal) has been prepared from the latest available environmental and technical information collected from a number of sources. The typical plant chosen for characterization is a 500-MWe nameplate rating pulverized-coal plant with an electrostatic precipitator, wet scrubber, and a wet-mechanical-draft cooling tower. It is a mine-mouth facility, with its own coal preparation plant.

The process, plant operating parameters, resources needed, and the environmental residuals and products associated with the power plant are presented in this secton in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 80 percent. While this capacity factor is representative of the reliability of generating units of this size, it does not consider unscheduled shutdowns for repairs of the plant and associated environmental control equipment or factors independent of the plant itself, e.g., reserve requirements.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of electric energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Twenty-three environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions, and a bibliography of cited references. Specific environmental regulations are discussed in the individual sections. The calculations of allowable emission levels are based on current Federal regulations applicable to new plants. For information on similar sized plants operating under previous Federal regulations, see Appendix A. For information on impending regulations, see Reference 1.

Section III discusses the overall physical requirements of the plant for land and water. A glossary of terms, cost information, and a trace element analysis are included as appendixes to this report. Data pertaining to additional subjects such as construction resources will be covered in a later version of this ECIR.

Reference

1. U.S. Department of Energy, Office of Technology Impacts, Office of Environment, "Environmental Issues Briefing Book for Policy Analysis Division," original issue April 1979 (compiled by the Mitre Corporation).

TABLE 1. SUMMARY SHEET

COAL-FIRED POWER PLANT (EASTERN BITUMINOUS COAL)

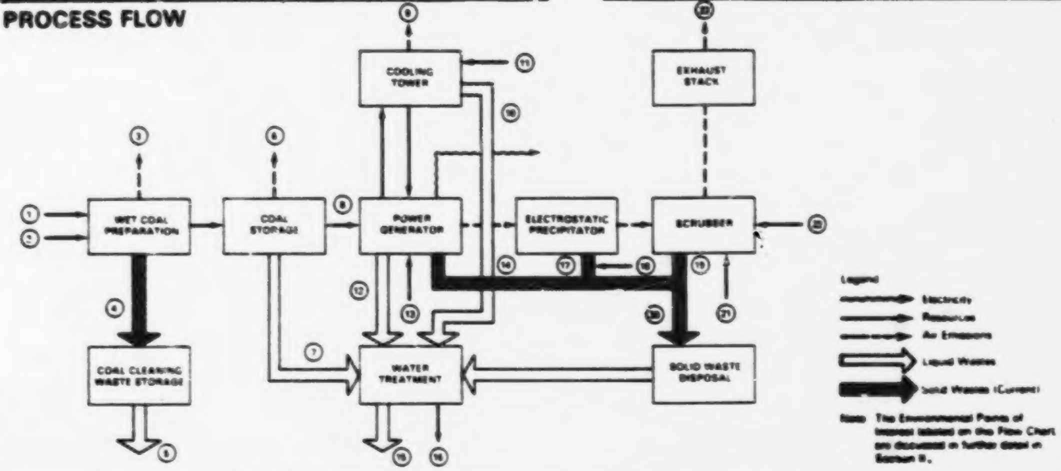
ENERGY SYSTEM DESCRIPTION

Mine-Mouth Conventional Steam Electric Power Plant Using Typical Eastern Bituminous Coal; No Cogeneration; Electrostatic Precipitator for Particulate Control; Wet Lime/Limestone Scrubber for SO_2 Control; Onsite Solid Waste Disposal and Onsite Water Treatment for Recirculation to Minimize Discharge. New Plant Subject to Current Regulations.

PLANT OPERATING PARAMETERS

Power Output to Grid:	500 MWe
Annual Capacity Factor:	80% (assumed)
Overall Plant Efficiency:	35%
Annual Energy Production:	12 x 10^{12} Btu (3.5 x 10^6 MWh)
Plant Lifetime:	30 yr

PROCESS FLOW



⑨
㉓
COOLING TOWER
⑪
⑩
EXHAUST STACK
③
⑥
①
②
WET COAL PREPARATION
COAL STORAGE
⑧
POWER GENERATOR
ELECTROSTATIC PRECIPITATOR
SCRUBBER
㉒
⑭
⑰
⑱
⑲
⑫
⑬
④
⑳
㉑
⑦
COAL CLEANING WASTE STORAGE
WATER TREATMENT
SOLID WASTE DISPOSAL
⑤
⑮
⑯
Legend
Electricity
Resources
Air Emissions
Liquid Wastes
Solid Wastes (Current)
Note: The Environmental Points of Interest labeled on the Flow Chart are discussed in further detail in Section II.

RESOURCES USED

Code No.	Resource	Quantities Used: Annual Usage*: English Units	Quantities Used: Annual Usage*: Metric Units	Quantities Used: Per 10^{12} Btu Energy Produced	Remarks
	Fuel				
①	Run-of-mine eastern bituminous coal	1.96 x 10^6 tons	1.77 x 10^6 tonnes	0.16 x 10^6 tons	High-sulfur coal (3.3% S)
⑧	Coal feed to boiler	1.43 x 10^6 tons	1.3 x 10^6 tonnes	0.12 x 10^6 tons	
	Water				
②	Coal preparation makeup water	40 x 10^6 gal	150 x 10^6 liters	3.3 x 10^6 gal	Quality not critical
⑪, ⑬	Power plant makeup water	2.38 x 10^9 gal	9 x 10^9 liters	0.19 x 10^9 gal	
⑱, ㉑	Environmental cleaning makeup water	32.4 x 10^6 gal	120 x 10^6 liters	2.7 x 10^6 gal	
	Raw Materials for Processing				
㉒	Limestone to scrubber	146 x 10^3 tons	132 x 10^3 tonnes	12.2 x 10^3 tons	
	Land				
④	Land for coal preparation solid waste storage (see Section III)	16 acres	6.5 ha	1.3 acres	Sufficient land needed for a 30-yr life
⑳	Land for power plant and environmental solid waste disposal (see Section III)	12.3 acres	5 ha	1.03 acres	Sufficient land needed for a 30-yr life
	Personnel				
	Power plant	135 man-yr		11.3 man-yr	
	Preparation plant	20 man-yr		1.7 man-yr	
	Raw Materials for Construction Facility Costs Control Costs	To Be Added			

*Based on the assumed 80% capacity factor

TABLE 1. (Continued)

COAL-FIRED POWER PLANT (EASTERN BITUMINOUS COAL)

ENVIRONMENTAL RESIDUALS AND PRODUCTS

		Quantities Released			
		Annual Levels*			
Code No.	Residual or Product	English Units	Metric Units	Per 10^{12} Btu Energy Produced	Regulatory Compliance Levels
	Air Pollutants				
③⑥	Fugitive dust from coal preparation and storage		Not quantifiable		
㉑	Post-Control Flue Gas Constituents				
	• Sulfur dioxide (SO_2)	10.2×10^3 tons	9.3×10^3 tonnes	860 tons	0.6 lb/10^6 Btu
	• Oxides of nitrogen (NO_x)	10.2×10^3 tons	9.3×10^3 tonnes	860 tons	0.6 lb/10^6 Btu
	• Total suspended particulates (TSP)	500 tons	455 tonnes	42 tons	0.03 lb/10^6 Btu
	• Nonmethane hydrocarbons (HC)	220 tons	200 tonnes	18 tons	Not established
	• Carbon monoxide (CO)	720 tons	655 tonnes	60 tons	
	• Carbon dioxide (CO_2)	3.7×10^6 tons	3.4×10^6 tonnes	0.3×10^6 tons	↓
	• Arsenic (As)	225 lb	102 kg	18.8 lb	
	• Beryllium (Be)	9.3 lb	4.2 kg	0.8 lb	
	• Cadmium (Cd)	4.1 lb	1.9 kg	0.4 lb	
	• Manganese (Mn)	161 lb	74 kg	13.4 lb	
	• Lead (Pb)	114 lb	52 kg	9.5 lb	
	• Selenium (Se)	56 lb	25 kg	4.7 lb	
	• Radium (Ra)	3×10^{-3} Ci		0.25×10^{-3} Ci	
	Water Pollutants				
⑨	Airborne water from cooling tower drift and evaporation	2×10^9 gal	7.6×10^9 liters	0.17×10^9 gal	
⑤	Surface run-off from coal preparation solid waste storage		Not quantifiable		
⑮	Excess water runoff from treatment/recycling holding ponds				
	• Total suspended solids (TSS)		30 mg/liter**		30 mg/liter***
	• Oil and greases		15.2 mg/liter		None
	• Copper		0.009 mg/liter		1 mg/liter***
	• Iron		0.009 mg/liter		1 mg/liter***
	• Chlorine		30.11 mg/liter		None
	Solid Waste				
④	Solid wastes from coal preparation (to storage)	0.5×10^6 tons	0.48×10^6 tonnes	0.04×10^6 tons	
⑭	Bottom ash from boiler (dry)	25×10^3 tons	22.8×10^3 tonnes	2.1×10^3 tons	
⑰	Collected fly ash (dry) from precipitator	100×10^3 tons	91×10^3 tonnes	8.3×10^3 tons	
⑲	Limestone scrubber sludge (dry)	193×10^3 tons	175×10^3 tonnes	16×10^3 tons	
	Heat				
⑧	Total heat losses to air	34×10^{12} Btu	10×10^6 MWh	2.8×10^{12} Btu	

Symbols and abbreviations are discussed in the acronyms and abbreviations section.

*Based on the assumed 80% capacity factor

**Estimated maximum concentrations for a 30-day average for a typical plant

***Kentucky water quality standards

OCCUPATIONAL SAFETY AND HEALTH

	Preparation Plant		Power Plant	
	Annual	Per 10^{12} Btu	Annual	Per 10^{12} Btu
Deaths	0.0033-0.0053	0.0003-0.0004	0-0.11	0-0.0095
Injuries	1.9-3.1	0.16-0.26	1.9-2.3	0.16-0.19

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II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

To identify current trends in coal-fired power plant design, the features of 43 modern plants were examined.[1] On the basis of the observed trends, and through discussions with power engineers, a typical plant was chosen for characterization. This composite plant is a 500-MWe pulverized-coal plant with an electrostatic precipitator to control particulate emissions; a wet lime/limestone scrubber for flue gas desulfurization; and a wet, mechanical draft cooling tower. The plant was assumed to be a mine-mouth facility with its own coal preparation plant.

The net station heat rate of 9760 Btu/kWh, which corresponds to an overall efficiency of 35 percent, was taken from an actual 500-MWe plant with similar controls and design features.[2] The coal used in the analysis is an eastern bituminous coal with a heat value of 12,000 Btu/lb, 3.3 percent sulfur, and 8.8 percent ash.[3]

The use of an eastern high-sulfur coal for electrical generation is shown in Figure 1. Twenty-three environmental points of interest have been identified in Figure 1 and are discussed in the following sections. Items ① through ⑤ deal with coal preparation, ⑥ and ⑦ deal with onsite coal storage, ⑧ through ⑬ deal with the generating plant itself, and ⑭ through ㉓ deal with pollution controls.

Cost information for the plant is given in Appendix B.

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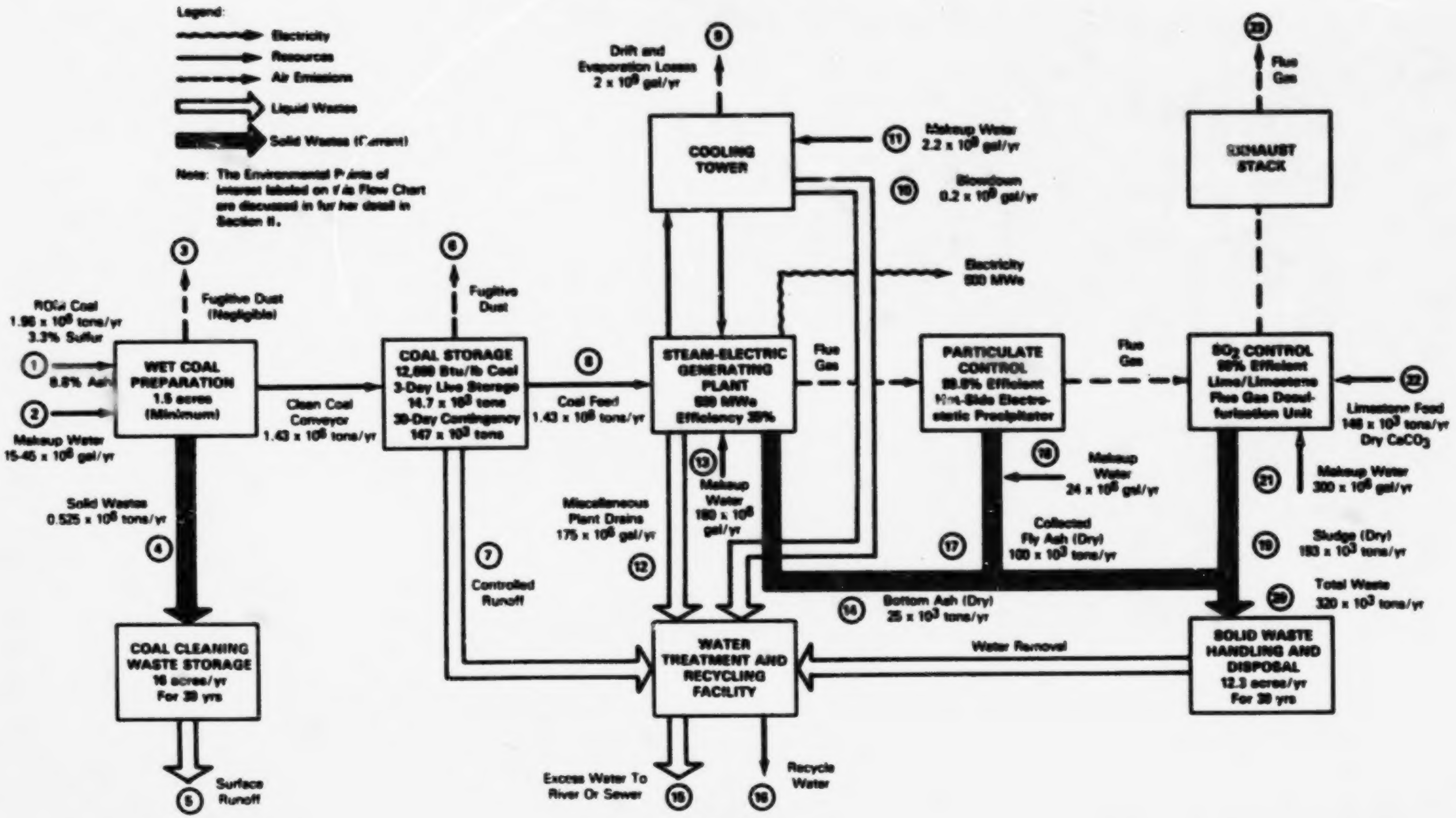
1. J.J. O'Connor, ed., Power, 1978 Plant Design Issue, Vol. 122, No. 11, November 1978.
2. Final Environmental Impact Statement, Spurlock Station, Unit No. 2 and Associated Transmission, USDA-REA-EIS-76-4F, Chapter 1, November 1976.
3. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Kentucky #11 Coal, McGraw-Hill, New York, New York, 1978.

FIGURE 1. PROCESS FLOW CHART WITH ENVIRONMENTAL POINTS OF INTEREST COAL-FIRED POWER PLANT (EASTERN BITUMINOUS COAL) 80% CAPACITY FACTOR


Legend:
Electricity
Resources
Air Emissions
Liquid Wastes
Solid Wastes (Current)
Note: The Environmental Points of Interest labeled on this Flow Chart are discussed in further detail in Section II.
ROM Coal
1.96 x 10^6 tons/yr
3.3% Sulfur
①
8.8% Ash
②
Makeup Water
15-45 x 10^6 gal/yr
③
Fugitive Dust
(Negligible)
WET COAL PREPARATION
1.5 acres
(Minimum)
Clean Coal
Conveyor
1.43 x 10^6 tons/yr
Solid Wastes
0.525 x 10^6 tons/yr
④
COAL CLEANING WASTE STORAGE
16 acres/yr
For 30 yrs
Surface
Runoff
⑤
⑥
Fugitive
Dust
COAL STORAGE
12,000 Btu/lb Coal
3-Day Live Storage
14.7 x 10^3 tons
30-Day Contingency
147 x 10^3 tons
⑦
Controlled
Runoff
⑧
Coal Feed
1.43 x 10^6 tons/yr
⑨
Drift and
Evaporation Losses
2 x 10^9 gal/yr
COOLING TOWER
⑪
Makeup Water
2.2 x 10^9 gal/yr
⑩
Blowdown
0.2 x 10^9 gal/yr
Electricity
500 MWe
STEAM-ELECTRIC GENERATING PLANT
500 MWe
Efficiency 38%
Flue
Gas
Miscellaneous
Plant Drains
175 x 10^6 gal/yr
⑫
⑬
Makeup
Water
180 x 10^6
gal/yr
PARTICULATE CONTROL
99.5% Efficient
Hot-Side Electrostatic Precipitator
Flue
Gas
⑱
Makeup
Water
24 x 10^6 gal/yr
⑰
Collected
Fly Ash (Dry)
100 x 10^3 tons/yr
⑭
Bottom Ash (Dry)
25 x 10^3 tons/yr
㉓
Flue
Gas
EXHAUST STACK
SO2 CONTROL
90% Efficient
Lime/Limestone
Flue Gas Desulfurization Unit
㉒
Limestone Feed
148 x 10^3 tons/yr
Dry CaCO3
㉑
Makeup Water
300 x 10^6 gal/yr
⑲
Sludge (Dry)
193 x 10^3 tons/yr
⑳
Total Waste
320 x 10^3 tons/yr
SOLID WASTE HANDLING AND DISPOSAL
12.3 acres/yr
For 30 yrs
Water Removal
WATER TREATMENT AND RECYCLING FACILITY
Excess Water To
River Or Sewer
⑮
Recycle
Water
⑯

① Run-of-Mine Coal to Coal Preparation

The amount of run-of-mine (ROM) coal to the coal preparation plant is 1.96 x 10^6 tons/yr.

The ROM coal is assumed to be extracted from an underground eastern mine (drift mine operating in thin seam (< 40 inches thick) bituminous coal).[1,2] The mined material is assumed to contain rock, slate, and other refuse normally associated with underground mining. The material has moisture, some of which occurs naturally, and some of which is added by in-mine sprays for dust control. The material is carried to the surface preparation plant by conveyor and to the out-of-mine sections, which are enclosed. No Federal regulations apply to the characteristics of the mined material.

To determine the quantity of ROM coal entering the preparation plant, the heat rate, the proposed operating power level of the power plant, and the operating characteristics of the coal preparation plant must be known. The typical power plant design used in this ECIR has a heat rate of 9760 Btu/kWh, and the generating plant operating level is 500 MWe. The coal preparation plant can operate effectively between 20 percent and 30 percent rejection rates.[2] It is assumed that the rejection rate for this coal in this preparation plant has been found empirically to be 27 percent. This typical operating point was established through review of similar circuit operation and accumulated operating experience.[3]

The calculations are as follows:

$$\begin{aligned} \text{Required heat input} &= (\text{Station power output})(\text{net station heat rate})(\text{hr/day}) \\ &= (5.0 \times 10^5\ \text{kWh/hr})(9760\ \text{Btu/kWh})(24\ \text{hr/day}) \\ &= 117 \times 10^9\ \text{Btu/day} \end{aligned}$$

Using the coal cleaning plant operating point of 27 percent rejection, the cleaned coal will have an energy content of 12,000 Btu/lb. Therefore,

$$\begin{aligned} \text{ROM coal into the preparation plant} &= \\ &\frac{(\text{heat input})}{(\text{coal heat content})(1 - \text{rejection rate})} \\ &= \frac{(117 \times 10^9\ \text{Btu/day})}{(12.0 \times 10^3\ \text{Btu/lb})(2 \times 10^3\ \text{lb/ton})(1 - 0.27)} \\ &= 6.7 \times 10^3\ \text{tons/day} \end{aligned}$$

On a yearly basis,

ROM coal into the preparation plant =
$(6.7 \times 10^3 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$
$= 1.96 \times 10^6$ tons/yr

The amount of ROM coal input for any preparation plant and power plant combination can be calculated for any coal by applying the plant's known heat rate, the typical preparation plant rejection rate, and cleaned coal Btu content to the above formulas.

References

1. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Kentucky #11 Coal, McGraw-Hill, New York, New York, 1978, p. 505 and pp. 920-921.
2. S.M. Cassidy, "Elements of Practical Coal Mining," Society of Mining Engineers, New York, New York, 1973, pp. 346-356.
3. P.J. Phillips and P.P. DeRienzo, "Assessing the Economics of Steam," Coal Preparation, Coal Mining and Processing, September 1977, p. 75.

② Makeup Water to Coal Preparation

The required makeup water for the coal preparation plant generally will not exceed 40 x 10^6 gal/yr.

The coal preparation plant assumed in this system design consists of crushing, washing, and sizing/screening operations, all of which are conducted in the presence of moisture (wet circuit). The system is designed to dewater the coal prior to delivery using screen and hydrocyclone separators and to recirculate the water in the system through a thickener to remove suspended solids. Some water will leave the plant as surface moisture on the clean coal and the rejected refuse material and must be made up by moisture arriving on the surface of the input ROM coal or from a makeup water source. The quality of this makeup water is not critical, and it may come from any of a number of sources such as wells, streams, or mine dewatering.

Because the surface moisture on the input coal is not highly controlled, the makeup requirement will be variable. In general, however, some makeup water will be required.[1]

While the makeup water requirement will vary with the preparation plant capacity, it is not necessarily directly scalable and will depend on empirical experience with a particular preparation circuit and ROM coal.[2] However, this value will not generally exceed 20 gal/ton of ROM coal processed, which equals 40 x 10^6 gal/yr at an 80-percent capacity factor.

References

1. S.M. Cassidy, "Elements of Practical Coal Mining," Society of Mining Engineers, New York, New York, 1973, p. 435.
2. Personal Communication, Mr. William Ostarello, Roberts and Schaefer Co. Engineers and Contractors, Chicago, Illinois, (312)-236-7292.

③ Fugitive Dust From Coal Preparation

Fugitive or stack particulate emissions from the coal preparation plant are negligible because no thermal drying or onsite open coal storage is employed.

Because the entire preparation facility is enclosed and the preparation circuit is operated in a wet mode, there is little opportunity for fugitive dust emissions from the plant.[1] Typical enclosed silo type coal storage would add little to these emissions if used. Exposed pile storage (seldom used in the east) could be the source of windblown dust if no dust control measures such as compacting, water sprays, or surface coatings are used.

If thermal drying of coal were used in this plant design, either to facilitate dry processing or for shipment preparation, dust emissions to the environment would occur. The uncontrolled emissions from three popular coal drying systems range from 15 to 25 lb of dust per ton of coal processed. The emissions to the atmosphere could be reduced to less than 0.075 lb/ton using cyclones followed by wet scrubbing.[1]

The low-level fugitive dust emission characteristics of total wet circuit processing plants are generally applicable to all plant sizes. The emissions factors for thermal drying are directly applicable to any size of processing unit.[1]

Reference

1. U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Third Edition, including supplements 1-7, PB 275-525, August 1977, pp. 346-347.

④ Solid Waste From Coal Preparation

The solid wastes discharged by the coal preparation plant amount to 0.525×10^6 tons/yr.

Solid waste discharged from the preparation plant consists of approximately 93 percent rock, slate, and shale; 2 percent coal fines rejected in the cleaning process; and 5 percent pyritic material.[1,2] The exact composition of this material will vary widely from coal to coal and as site mining conditions change, but the coal content will be kept to a minimum.[2] Analyzed samples of contemporary coal preparation plant waste piles show concentrations of pyritic material ranging from 7.7 percent for fines (the size fraction in which pyrites would be expected to concentrate) to 3.1 percent in course rewash refuse.[2]

The calculation is as follows:

$$\text{Coal preparation waste} = (\text{Rejection rate})(\text{ROM coal feed rate})$$

For the typical plant,

$$\begin{aligned}\text{Coal preparation waste} &= (0.27)(6.7 \times 10^3 \text{ tons/day}) \\ &= 1800 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Coal preparation waste} &= (1800 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.525 \times 10^6 \text{ tons/yr}\end{aligned}$$

This material is transported with associated moisture (10 to 15 percent) to nearby surface landfill where it will be compacted and rehabilitated through revegetation and stabilization techniques.[3] Such sites must be designated and permitted by state/local authorities. Section III discusses land requirements for solid waste disposal. Water control must be installed for both surface and subsurface drainage of the area.

The production of solid waste for a given coal and a given preparation plant is linearly scaleable for changes in plant coal use. As more rock or slate enters in the ROM coal, as in coal from thinner seams, the rock refuse fraction can be expected to rise accordingly, but the coal fines fraction and the pyritic material fraction can be expected to remain constant, based on the clean coal plant output.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 47.
2. C. Treworgy, Illinois Geological Survey, In House Studies of Processing Wastes, April 2, 1980.
3. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15435-15439.

⑤ Surface Runoff From Coal Preparation Waste Storage

Surface runoff for coal processing disposal sites is, in general, not quantifiable because it depends on rainfall and subsurface water quantities that may come in contact with the waste material.[1]

Runoff from coal cleaning refuse waste piles will originate from two sources: rainfall on the surface of the fill and subsurface water including moisture on the surface of the material. The requirement to cover with "topsoil" and revegetate and control drainage on the surface of the disposal area will, in general, isolate the rainfall and surface water from the waste material.[1,2] Subsurface water can more readily come in contact with the waste material and this contact can result in the dissolving of solids (forming, for example, sulfates); the acidification of the liquids; or the deposition of suspended solids in the liquid. It is possible that a properly designed and operated drainage system will result in acceptable water quality for discharge to surface waters. If this quality cannot be achieved, treatment of the drainage from the area may be necessary to meet local regulations for dissolved solids, suspended solids, and acidity.[3]

For this processing plant, the dry landfill method of disposal has been chosen. As the surface area of the fill increases, there will be a general increase in the opportunity for ingress of surface (rain) water and for intrusions of subsurface water. Neither of these sources can be accurately quantified.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 48.
2. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15434-15436 and 15424-15430.
3. Personal Communication, Harry Chappel, Illinois Environmental Protection Agency, April 3, 1980.

⑥ Fugitive Dust From Onsite Coal Storage

It is not possible to accurately quantify the fugitive dust emissions from the coal storage area. Wind erosion resulting in airborne dust should not be a significant air pollution source for active piles if dust control measures are maintained.

Coal fines are an inevitable[1,2] result of coal preparation and handling operations. Dust emissions from the storage areas, especially active storage, can be effectively controlled through the use of water sprays and surface compaction. In addition, oil, asphalt, or latex coatings can be applied to long-term storage piles to control dust emissions. It should also be noted that the surface of a properly compacted long-term storage pile will quickly lose the fines, which can become airborne, and the dust emissions will drop to a very low level unless the pile is physically disturbed.

The dust emissions from an open coal storage pile are not, in general, quantifiable. They are, however, proportional to the exposed surface of the coal pile and generally will increase with increases in surface wind velocity.[2]

References

1. T.H. Pigford et al., "Fuel Cycles for Electrical Power Generation," EEED-101 Teknekron, Inc., Berkeley, California, January 1973.
2. U.S. Environmental Protection Agency, "Survey of Fugitive Dust From Coal Mines," EPA-908/1-78-003, February 1978, pp. 2 and 56.

⑦ Controlled Runoff From Onsite Coal Storage

It is not possible to accurately quantify the liquid runoff from the coal storage areas because the source of this liquid is primarily rainfall and, to a lesser extent, the water sprays that may be used to control dust.[1]

Subsurface water is excluded from the area by a liner, usually clay or an impermeable membrane. Water that falls on the surface of the coal pile will either be lost to the air through evaporation or be drained to a peripheral drainage channel where it can be routed to the power plant water treatment system. This water may contain suspended solids and dissolved solids; be slightly acidic; and contain oil, if oil sprays are used in dust control. The receiving water treatment system is designed to handle such pollutants through settling, neutralization, oil removal, and blending to achieve acceptable water quality for either recycling uses in the system or discharge to surface water.

The quantity of runoff is generally proportional to the surface area of the coal storage pile and the relative quantity of precipitation at the site.

Reference

1. U.S. Environmental Protection Agency, "Environmental Assessments of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, pp. 44 and 45.

⑧ Coal Feed to Generating Plant

The amount of prepared coal required for a typical 500 MWe power plant operating at 80% annual capacity is 1.43 x 10⁶ tons/yr.

To determine how much coal is required to run any given power plant, the following information is needed:

- Net power delivered to the transmission grid (P) in MWe
- Net station heat rate ($\dot{Q}$) in Btu/kWh
- Heat content of coal, as fired (Q) in Btu/lb

The power delivered to the grid is known for a given plant (i.e., the nominal rating of 500 MWe, 1000 MWe, etc.)

The net station heat rate ($\dot{Q}$), which varies from plant to plant, is a measure of the amount of heat (Btu) that must be fed into the boiler to get 1 kWh of electricity out to the grid. Net power delivered to the grid equals total power generated minus power required to operate plant auxiliaries, including environmental control equipment. The actual overall plant heat rate is listed in the plant's major documents, such as the Environmental Impact Statement or the Power Plant Design Report.

The heat content of coal (Q) as fired is a parameter given in the coal analysis.

Using the above definitons, the coal required on a daily basis is as follows:

$$\frac{(P)(\dot{Q})}{Q}\left[\left(\frac{1 \times 10^3 \text{ kWe}}{\text{MWe}}\right)\left(\frac{1}{2 \times 10^3}\,\frac{\text{ton}}{\text{lb}}\right)\left(2.4 \times 10\ \frac{\text{hr}}{\text{day}}\right)\right] = 12\ P\dot{Q}/Q \text{ tons/day}$$

In the typical plant,

$P = 500$ MWe
$\dot{Q} = 9760$ Btu/kWh
$Q = 12{,}000$ Btu/lb

Thus, for the typical plant,

$$\text{Coal feed rate} = 12\ P\dot{Q}/Q \text{ tons/day}$$

$$\text{Coal feed rate} = \frac{12\ (500 \text{ MWe})(9760 \text{ Btu/kWh})}{12{,}000 \text{ Btu/lb}}$$

$$= 4.9 \times 10^3 \text{ tons/day}$$

On a yearly basis,

$$\text{Coal feed rate} = (4.9 \times 10^3 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 1.43 \times 10^6 \text{ tons/yr}$$

The analysis for the coal used in this ECIR is as follows[1]:

Proximate Analysis (%)	
ash	8.8
fixed C	44.3
volatile	38.7
moisture	8.2

Ultimate Analysis (%)	
C	64.9
O	8.7
H	4.6
N	1.5
S	3.3
ash	8.8
moisture	8.2

Heat value -- 12,000 Btu/lb

In subsequent sections of this ECIR, values from this coal analysis are used to calculate the resources and residuals associated with operation of the plant, e.g., in item ⑭, Bottom Ash From Coal Combustion, the ash content of the coal is used to calculate the amount of bottom ash from combustion. If a coal different from the one shown in the above table were used, the values from the new coal analysis would be substituted in the equations.

In the calculations of environmental pollutants, it is assumed that 20 percent of the ash is emitted as bottom ash and that the remaining 80 percent is emitted from the boiler as fly ash.[2,3] It is also assumed that 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and the remaining 90 percent is converted to sulfur dioxide.[4,5]

The energy content of the coal feed into the boilers is converted into electricity with an efficiency of 35 percent. The remainder of the energy is lost in the form of thermal energy according to the following table.[6]

	Percent of Input	Energy at 100-Percent Capacity (Btu/day)
Net Electrical Output	35	41×10^9
Heat Rejected to Condenser	50	58.5×10^9
Sensible Heat in Flue Gas	10.7	12.5×10^9
Internal Thermal Losses and Plant Consumption	4.3	5×10^9
Total Energy From 4.9×10^3 tons/day Coal Feed at 12,000 Btu/lb	100	117×10^9

These heat losses pose little environmental concern: the heat rejected directly to the atmosphere is negligible, the heat rejected to the main condenser is cooled by closed-cycle cooling towers, and heat rejected through the cooling tower blowdown line is dissipated into the atmosphere through water treatment/recycling facility holding ponds.

References

1. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Kentucky #11 Coal, McGraw-Hill, New York, New York, 1978.
2. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
3. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
4. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C, April 1980.
5. Personal Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality, Planning, and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
6. Teknekron, Inc., "Towards Comprehensive Standards: The Electric Power Case," EPA No. 68-01-0561, January 1973, p. 70.

⑨ Evaporative and Drift Losses From Wet Cooling Towers

Evaporative losses from the cooling towers into the atmosphere are approximately 2 x 10^9 gal/yr for a typical 500-MWe power plant operating at full load. Additionally, another 0.25 percent or 5 x 10^6 gal/yr will be lost in the form of drift if drift eliminators are not used.

The above values are based on the assumptions that 50 percent of the gross heat released from coal combustion is dissipated to the circulating water system and that the water heat of vaporization at standard conditions is 1050 Btu/lb water evaporated.[1,2,3] In general, the water requirements due to cooling tower evaporation are given by

$$W_{EVAP}, \text{ gal/day} = 2880 \text{ (percent heat rejected to circulating water system)} \, \dot{Q}P/\text{(water heat of vaporization)}$$

For the typical plant,

$$\begin{aligned} W_{EVAP} &= (2880)(0.50)(9760 \text{ Btu/kWh})(500 \text{ MWe})/(1050 \text{ Btu/lb}) \\ &= 6.7 \times 10^6 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{EVAP} &= (6.7 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 2 \times 10^9 \text{ gal/yr} \end{aligned}$$

Similarly, requirements due to cooling tower drift for the typical plant are

$$\begin{aligned} W_{DRIFT} &= 0.0025 \, W_{EVAP} \\ &= 0.0025 \, (6.7 \times 10^6 \text{ gal/day}) \\ &= 16.8 \times 10^3 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$W_{DRIFT} = (16.8 \times 10^{3}\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr})$$
$$= 4.91 \times 10^{6}\ \text{gal/yr}$$

These cooling tower losses may interact with the local meteorology and cause visibility impairment, fogging, or icing conditions. There are no existing regulations limiting cooling tower losses to the atmosphere.

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 61-105.
3. Power Handbook: Basic Power Facts Made Easy, Part One and Part Two, Power Magazine, 1975, p. 104.

⑩ Cooling Tower Blowdown

Cooling tower blowdown represents approximately 10 percent of the evaporation losses.[1,2] *For a typical plant, blowdown is 0.2×10^9 gal/yr and goes to the water treatment/recycling facility to be reused as makeup water.*

Blowdown water typically contain the following environmental residuals: biocides (e.g., chlorine), added for marine and biological growth control; corrosion inhibitors (e.g., chromates), a high concentration of total dissolved solids; and excess heat. Because these residuals are collected and controlled in the water treatment/recycling facility, there is no direct influence on the environment (see item ⑮, Excess Water to River or Sewer).

For any plant,

$$W_{BLOWDOWN} = 0.1\ W_{EVAP}$$

For the typical plant,

$$W_{BLOWDOWN} = 0.1\ (6.7 \times 10^6 \text{ gal/day})$$

$$W_{BLOWDOWN} = 0.7 \times 10^6 \text{ gal/day}$$

On a yearly basis,

$$\begin{aligned} W_{BLOWDOWN} &= (0.7 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.2 \times 10^9 \text{ gal/yr} \end{aligned}$$

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, p. 47.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 69.

⑪ Cooling Tower Makeup

Approximately 2.2 x 10^9 gal/yr are needed to make up cooling tower losses due to drift, evaporation, and blowdown for a typical plant.

Cooling tower makeup is obtained by summing W_{EVAP} and W_{DRIFT} from item ⑨, Evaporative and Drift Losses From Wet Cooling Towers, and $W_{BLOWDOWN}$ from item ⑩, Cooling Tower Blowdown, as follows:

$$\boxed{W_{TOW} = W_{EVAP} + W_{DRIFT} + W_{BLOWDOWN}}$$

For the typical plant,

$$\begin{aligned} W_{TOW} &= (6.7 \times 10^6 \text{ gal/day}) + (0.02 \times 10^6 \text{ gal/day}) + (0.67 \times 10^6 \text{ gal/day}) \\ &= 7.4 \times 10^6 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{TOW} &= (7.4 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 2.2 \times 10^9 \text{ gal/yr} \end{aligned}$$

The above analysis is for a wet cooling system only. When water is expensive, however, (greater than about \$0.80/10^3 gallons) or of limited availability, combined wet and dry cooling systems would be used. For such systems, the average annual water consumption is between 10 and 25 percent of the all wet system.[1]

Reference

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.

⑫ Miscellaneous Plant Drains

The typical liquid waste flow from miscellaneous plant drains is 175 x 10^6 gal/yr, all of which goes to the water treatment/recycling facility.[1]

The liquid waste consists of various water streams used in maintaining plant operation (e.g., boiler blowdown and bearing cooling) and can be slightly contaminated with oil or chemicals. The typical liquid waste flow from miscellaneous plant drains is 175 x 10^6 gal/yr, all of which goes to the water treatment/recycling facility.[1] This information was design data from an operating 500-MWe power plant.[1] Because the magnitude of the waste stream is not a linear function of plant power level, the waste from a power plant of a size other than 500 MWe should be obtained from an actual plant of that size. Such information is contained in the plant's Environmental Impact Statement.

The chemical nature of the waste stream as potentially released to the environment is discussed in item ⑮, Excess Water to River or Sewer.

Reference

1. Environmental Analysis, Spurlock Station Unit No. 2, Docket No. 6500-05, July 1975, p. II-54.

⑬ Makeup Water to Generating Plant

The makeup water to the generating plant is 180×10^6 gal/yr.

Makeup water is required for two purposes: for the operations discussed in item ⑫, Miscellaneous Plant Drains, and for handling bottom ash from the boiler.

Bottom ash is collected and quenched in water-filled hoppers before it is sluiced to a disposal site. The rate at which water is evaporated from the hopper, W_{VAP}, is a function of the ash specific heat, temperature drop, quenching rate, and water heat of vaporization,[1] i.e.,

$$\begin{aligned} W_{VAP}\text{, gal/day} = {} & 240 \text{ (ash fraction in coal)(coal feed rate)(bottom ash fraction)} \\ & \text{(bottom ash temperature change)(bottom ash specific heat)/} \\ & \text{(water heat of vaporization)} \end{aligned}$$

For the typical plant, if it is assumed that

Ash removal temperature = 1200° F
Ash quenched temperature = 200° F
Ash specific heat = 0.2 Btu/lb-° F
Water heat of vaporization = 1.050×10^3 Btu/lb
Bottom ash fraction = 0.2

then

$$\begin{aligned} W_{VAP} &= 240\ (0.088)(4.9 \times 10^3 \text{ tons/day})(0.2)(1000^{\circ}\text{F})(0.2 \text{ Btu/lb-}^{\circ}\text{F})/(1050 \text{ Btu/lb}) \\ &= 3.9 \times 10^3 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{VAP} &= (3.9 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 1.14 \times 10^6 \text{ gal/yr} \end{aligned}$$

Of equal importance to the water evaporated is the amount of excess water needed for bottom ash handling and disposal, W_{HAD}. If the weight of water remaining in the quenched ash is 30 percent of the ash weight,[1] then

$$W_{HAD}\text{, gal/day} = 72\ (\text{ash fraction in coal})(\text{coal feed rate})(\text{bottom ash fraction})$$

For the typical plant,

$$\begin{aligned} W_{HAD} &= 72\ (0.088)(4.9 \times 10^3 \text{ tons/day})(0.2) \\ &= 6.2 \times 10^3 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{HAD} &= (6.2 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 1.81 \times 10^6 \text{ gal/yr} \end{aligned}$$

The total water requirement for bottom ash disposal, W_{BA}, is therefore given as

$$W_{BA} = W_{VAP} + W_{HAD}$$

For the typical plant,

$$\begin{aligned} W_{BA} &= (3.9 \times 10^3 \text{ gal/day}) + (6.2 \times 10^3 \text{ gal/day}) \\ &= 10.1 \times 10^3 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{BA} &= (10.1 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 3 \times 10^6 \text{ gal/yr} \\ &= 0.03 \times 10^8 \text{ gal/yr} \end{aligned}$$

The majority of this water will be supplied from recycled water (see item ⑯, Recycle Water). Thus, the total makeup water requirement for the generating plant is the 1.75×10^8 gal/yr for general plant operations (see item ⑫, Miscellaneous Plant Drains) plus the 0.03×10^8 gal/yr given above, or 1.78×10^8 gal/yr $\approx 180 \times 10^6$ gal/yr.

Reference

1. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, Chapter 8, August 24, 1976, p. 141.

⑭ Bottom Ash From Coal Combustion

The amount of bottom ash generated is 25 x 10^3 tons/yr.

As described earlier, the quantity of ash in the coal assumed for this ECIR is 8.8 percent, and 20 percent of this ash becomes bottom ash.[1,2] Thus,

Bottom ash = (ash fraction in coal)(coal feed rate)(bottom ash fraction)

For the typical plant:

$$\text{Bottom ash} = (0.088)(4.9 \times 10^3 \text{ tons/day})(0.20)$$
$$= 86 \text{ tons/day}$$

On a yearly basis,

$$\text{Bottom ash} = (86 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 25 \times 10^3 \text{ tons/yr}$$

Bottom ash from a dry bottom pulverized coal boiler is collected and quenched in hoppers, located beneath the boiler, where it is sluiced with water to settling ponds or dewatering bins.[3]

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plant in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 142.

⑮ Excess Water to River or Sewer

Whenever the holding pond from the water treatment/recycling facility overflows during low demand periods, the excess water is directed to the area surface waters (lake or river) or to a sewer system.

The quantity and quality of the overflow is controlled to within standards established by either the Federal Government or the state based on National Pollutant Discharge Elimination System (NPDES) procedures and guidelines.[1,2,3] Projections for the typical coal-fired 500-MWe power plant show that the maximum flow rate from the holding ponds under worst-case conditions is 26 x 10^6 gal/day.[4] The maximum daily average concentration of controlled residuals observed for 30 consecutive days and the amount of residuals that would be released at the maximum flow rate are as follows:[4]

Residual	Maximum Amount Released	Maximum Measured Concentration (mg/l)	Kentucky Water Quality Standards (mg/l)
Total Suspended Solids	3.3 tons/day	30	30
Oil and Greases	1.7 tons/day	15.2	None
Copper	2 lb/day	0.009	1
Iron	2 lb/day	0.009	1
Chlorine	24.2 lb/day	0.11	None

Where

Maximum amount released per day = (Maximum flow rate)(Maximum average 30-day concentration)

The allowable concentrations of the pollutants shown above are specified by the appropriate state NPDES permitting authority[5] based on Federal regulations in the Clean Water Act, local pollutant regulations, and the water quality characteristics of the receiving water.

The 26 x 10^6 gal/day worst-case discharge is not characteristic of the expected flow. The actual flow would be considerably lower and would depend on site-specific conditions, such as precipitation.

References

1. Federal Water Pollution Control Act, P.L. 92-500 (as ammended), 1972.
2. Clean Water Act, P.L. 95-217, 1977.
3. U.S. Environmental Protection Agency, "A Guide to New Regulations for the NPDES Permit Program," C-1, June 1979.
4. Environmental Analysis, Spurlock Station Unit No. 2, Docket No. 6500-05, July 1975, p. II-55.
5. Personal Communication, Division of Water Quality, Kentucky Department of Natural Resources and Environmental Protection, (502) 564-2126.

⑯ Recycle Water

Recycled water can be used for the solid waste handling requirement of 29.2×10^6 gal/yr.

Recycle water in this plant configuration is water that has been withdrawn from the plant water treatment system after settling, oil removal, and acidic neutralization. This water will contain varying degrees of dissolved solids as well as suspended particulates. In general, it will be of such quality that it could be discharged to surface waters.

The amount of water required in solid waste handling systems, assuming a 50-percent total solids mixture is given by[1]

$$\begin{aligned}\text{Water required, gal/day} = 240\,[&(\text{bottom ash, dry}) + (\text{fly ash, dry}) \\ &+ (\text{scrubber sludge, dry}) - (\text{water in scrubber sludge})]\end{aligned}$$

For the typical plant,

$$\begin{aligned}\text{Water required} &= 240\ [86\ \text{tons/day} + 345\ \text{tons/day} + 660\ \text{tons/day} - 660\ \text{tons/day}] \\ &= 0.1 \times 10^6\ \text{tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Water required} &= (0.1 \times 10^6\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 29.2 \times 10^6\ \text{gal/yr}\end{aligned}$$

The amount of recycle water required for ash handling is directly and linearly scalable with plant capacity for a given coal and scrubber operation and will increase linearly as the dry solids to be transferred increase.

Reference

1. Final Environmental Impact Statement, Spurlock Station Unit No. 2, and Associated Transmission, USDA-REA-EIS-76-4F, November 1976.

⑰ Fly Ash From Particulate Control

The total amount of fly ash generated is 100 x 10^3 tons/yr.

Dry electrostatic precipitators are used to remove the coal fly ash from the flue gas. Eighty percent of the ash in the coal is emitted as fly ash,[1,2] or

Fly ash = (ash fraction in coal)(coal feed rate)(fly ash fraction)

For the typical plant,

Fly ash = (0.088)(4.9 x 10^3 tons/day)(0.80)
= 345 tons/day

On an annual basis,

Fly ash = (345 tons/day)(0.8 capacity factor)(365 days/yr)
= 100 x 10^3 tons/yr

To meet the current NSPS of 0.03 lb/10^6 Btu, only 0.5 percent of this amount is emitted to the ambient atmosphere, and 99.5 percent is captured by the electrostatic precipitator.

From these precipitators, the collected ash is discharged into storage hoppers by rapping. The dry fly ash is transported by pneumatic conveying from the precipitator to the sluicing system, where it will become part of the bottom ash scrubber sludge mixture.[3]

A second particle control technology now in use and gaining in popularity is the baghouse. Although the technology has been applied to large utility boilers both in the East and in the West, it is more predominantly applied in the West to collect the high resistivity fly ash from western coals that is difficult to collect in an ESP[4] and to meet more stringent particulate emission standards imposed by some western states. Baghouses generally have higher collection efficiencies than ESPs (96 to 99.5 percent for ESPs versus >99 percent for baghouses in most cases) and are especially effective in the control of fine particles ($<3\mu$). If a baghouse is to be considered, the assumed collection efficiency of the unit can be directly substituted in the example given in place of the 99.5 percent removal efficiency assumed for the ESP. Although the removal efficiency is variable for both ESPs and baghouses, the individual utilities will generally operate the units to meet the standards that apply in each specific case.

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 144.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards," EPA-450/2-78-006a, July 1978 p. 4-1.

⑱ Makeup Water for Fly Ash Transport

Water added to the captured fly ash to transport it to the disposal area is 24×10^6 gal/yr.

Dry electrostatic precipitators are used to remove the coal fly ash from the flue gas. In these precipitators, the collected ash is discharged into a sluicing system by rapping. The ash is then combined with recycle water until the mixture is at least 50-percent liquid by weight.[1] Note that the fly ash, bottom ash, and scrubber sludge are all individually fed into the sluicing system.

The amount of water required to transport the ash in the sluicing system is given as

$$\boxed{\text{Water required, gal/day} = 240\ (\text{ash fraction in coal})(\text{coal feed rate})(\text{fly ash fraction})}$$

For the typical plant,

$$\boxed{\begin{aligned}\text{Water required} &= 240\ (0.088)(4.9 \times 10^3\ \text{tons/day})(0.8)\\ &= 83 \times 10^3\ \text{gal/day}\end{aligned}}$$

On a yearly basis,

$$\boxed{\begin{aligned}\text{Water required} &= (83 \times 10^3\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr})\\ &= 24 \times 10^6\ \text{gal/yr}\end{aligned}}$$

Reference

1. Electric Power Research Institute, "FGD Sludge Disposal Manual," FP-977, January 1979, p. 4-7, Table 4-2.

⑲ Sludge From SO_2 Control

The amount of scrubber sludge generated (on a dry basis) is 193 x 10^3 tons/yr.

The use of a limestone scrubber is assumed for SO_2 control based on the current number of such units in operation and their combined record of effectiveness and reliability. The operation of such units involves the creation and requirement for disposal of sludge (spent reactants mixed in the same ratio with water).

The quantity of sulfur in the coal used is 3.3 percent. Therefore, the quantity of sulfur entering the boiler is

$$\begin{aligned} S &= (\text{sulfur fraction in coal})(\text{coal feed rate}) \\ &= 0.033\ (4.9 \times 10^3\ \text{tons/day}) \\ &= 162\ \text{tons/day} \end{aligned}$$

If it is assumed that a total of 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and that the remainder of the sulfur is converted to SO_2, then

$$\begin{aligned} SO_2 &= 0.9\ (\text{sulfur entering boiler})(2) \\ &= 0.9\ (162\ \text{tons/day})(2) \\ &= 292\ \text{tons/day} \end{aligned}$$

Thus, 292 tons/day of SO_2 enter the scrubber.[1-4] (Note: The factor "2" in this equation is used because every mole of sulfur requires 1 mole of oxygen to form 1 mole of SO_2.) As will be shown in item ㉒, Lime/Limestone Requirement for SO_2 Control, the amount of dry limestone used is 500 tons/day, i.e., 1.25 times the stoichiometric requirement. This excess 25 percent of the stoichiometric requirement will become part of the sludge residue. It is generally accepted[5] that the spent slurry consists of 75 percent $CaSO_3 \cdot \frac{1}{2}H_2O$ and 25 percent $CaSO_4 \cdot 2H_2O$. As will be shown in item ㉓, Flue Gas, the scrubber must operate at 88 percent efficiency to meet the standard. Consequently, the amount of scrubber sludge (dry basis) generated each day is

$$\begin{aligned} \text{Sludge (dry)} &= [0.25\ (100/64) + (140/64)](\text{scrubber efficiency})(SO_2\ \text{feed rate}) \\ &= [0.25\ (100/64) + (140/64)](0.88)(292\ \text{tons/day}) \\ &= 660\ \text{tons/day} \end{aligned}$$

On a yearly basis,

$$\text{Sludge (dry)} = (660\ \text{tons/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) = 193 \times 10^{3}\ \text{tons/yr}$$

where

100/64 = limestone/SO_2 molecular weight ratio
140/64 = ($CaSO_3 \cdot \frac{1}{2}H_2O$ and $CaSO_4 \cdot 2H_2O$) mixture/SO_2 molecular weight ratio

Based on current usage and projections of new installations, lime/limestone scrubbers are the most popular form of SO_2 control now available and are expected to remain so in the foreseeable future. Other SO_2 control systems have been demonstrated at utility scale, however. These include sodium carbonate scrubber systems, dual alkali scrubber systems, Wellman-Lord regenerative scrubber systems, magnesium oxide regenerative scrubber systems, and dry lime or alkali injection systems. Although these systems are now or have been in commercial operation, their overall number is small and for this reason have not been included in the detailed evaluation of control technology. The major points of environmental interest for these systems are generally the same as those for lime/limestone. The interest in these systems centers primarily on their potential for desirable modification or reduction in the waste (generally considered solid waste) streams from the process.

Although the current NSPS for SO_2 control excludes the use of low-sulfur coal alone to achieve compliance, low-sulfur coal can be used in combination with other SO_2 removal techniques to achieve a more desirable system from the standpoint of reliability, economics, or both. For those plants operating under the previous Federal NSPS, the use of low-sulfur coal is a viable option to achieve the 1.2 lb/10^6 Btu SO_2 emission limit. Older plants, not controlled by Federal regulations, may also use low-sulfur coal to comply with applicable state and local SO_2 standards.

References

1. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C.
2. Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
3. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA-450/2-78-007a, July 1978.
4. U.S. Environmental Protection Agency, "Position Paper on Regulation of Atmospheric Sulfates," EPA-450/2-75-007, September 1975.
5. Aerospace Corporation, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-0446, March 1978.

⑳ Solid Waste Handling

The typical plant and associated pollutant controls generate 320 x 10^3 tons/yr (dry basis) of solid sludge.

Waste streams entering the disposal site contain pyrites sluiced from the coal pulverizer and bottom ash sluiced from the boiler, fly ash sluiced from the electrostatic precipitator, and scrubber sludge underflow from a thickener located downstream of the scrubber. The scrubber wastes in the disposal site settle to approximately 50 percent solids. Excess water, i.e., from the settling of the scrubber sludge and unevaporated rainwater, is returned to the water treatment/recycle facility.

The wastes are contained in impoundments formed by the excavation of the disposal site. Sides of the impoundment are sloped and extend above grade level to complete the basin and form berms and dikes around the periphery of the site. A total depth of 30 ft of waste material is considered typical.

For the typical plant, determination of total solid wastes on a dry basis and required land area are as follows:

1.

86 tons/day	bottom ash
345	fly ash
560	reacted limestone (75%:$CaSO_3 \cdot \frac{1}{2} H_2O$ & 25%:$CaSO_4 \cdot 2\ H_2O$)[1]
+100	unreacted limestone
1100 tons/day	(solids, dry) at 88.6 lb/ft^3

2. Adding sluicing water results in

+1100 tons/day	(sluicing water)
2200 tons/day	wet waste

3. To determine land required:[2]

$$\left(2200\ \frac{\text{tons}}{\text{day}}\right)\left(2000\ \frac{\text{lb}}{\text{ton}}\right)\left(\frac{1}{88.6}\ \frac{\text{ft}^3}{\text{lb}}\right)\left(\frac{1}{30}\ \text{ft} \times \frac{1}{43{,}560}\ \frac{\text{acre}}{\text{ft}^2}\right)\left(1.1,\ \text{impoundment size factor}\right)\left(365\ \frac{\text{days}}{\text{year}}\right) = 15.3\ \frac{\text{acres}}{\text{year}}$$

4. This results in a land acreage requirement of

$$\left(15.3\ \frac{\text{acres}}{\text{year}}\right)\left(30\ \frac{\text{years}}{(\text{life})}\right) = 460\ \text{acres at 100 percent capacity factor}$$

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On an annual basis,

Sludge = (1100 tons/day)(0.8 capacity factor)(365 days/yr)
= 320 x 10^3 tons/yr

and

Land requirement = (460 acres/yr)(0.8 capacity factor)
= 370 acres for 30 years, 30 feet deep

Regardless of the solid waste treatment or stabilization method used, upon filling of the disposal impoundment, it is expected that a layer of soil will be placed over the wastes and will be graded and sloped to encourage rainwater runoff and to minimize seepage of rainwater through the wastes.

Three alternative sludge treatment and stabilization methods are available for disposal of the wastes: (1) Settling the wastes over an impervious layer and decauting of supernatant liquid; the impervious material can be clay or an elastomeric liner with a permeability coefficient of 10^{-7} cm/sec or less. (2) Reducing the leachability of the waste (to 10^{-5} to 10^{-7} cm/sec) by chemically treating the scrubber sludge-ash waste with lime, forming a solid material with low permeability characteristics and high load-bearing characteristics.[2] (3) Installing an underdrainage or dewatering system of perforated pipes in the soil immediately below the sludge-soil interface. Settling of the wastes up to 60 percent solids has been observed.[2] Further settling to 80 percent solids (with a correspondent reduction of waste volume and disposal land area) can be achieved if the scrubber sludge were oxidized to gypsum within the scrubber or in an oxidation tower downstream of the scrubber.

Decisions on the use of these alternatives will be based on site-specific considerations, including sludge and soil characteristics, land reclamation requirements, and cost factors.

Radon Emanation From Solid Waste Storage

Analysis of the ash produced by the combustion of bituminous coal has shown that a power plant solid waste burial site will emit approximately 2.23 x 10^{-4} Ci/day of radioactive radon-222 gas for every acre of covered solid waste disposed of. Over a 30-year plant lifetime, radon (Rn) emissions will average 4.1×10^{-2} Ci/day for a typical 500-MWe plant, assuming that all of the solid wastes are buried with approximately 2 ft of earth cover at the power plant site and the plant operates at an average capacity factor of 80 percent.

Radon emanation from ash piles is a function of the concentrations of radium-226 in the waste material, surface area and depth of the buried waste, and the depth of earth cover over the waste. Waste containing radium-226 (the parent nuclide of radon-222 gas) buried at a depth of 10 ft will emit approximately the same amount of radon gas as waste buried in deeper layers because of the self-shielding effect of the waste. Using data collected by the U.S. Geological Survey,[3] Goldman has shown that the annual radon-222 gas emissions from Appalachian coal ash waste with a radium-226 concentration of 3.48 pCi/gm would be 0.191 Ci/acre-yr assuming a 25-percent reduction due to a 2-ft earth cover.[4]

Using these data and adjusting for the higher radium-226 concentration assumed in item 23, Flue Gas, a radon gas emanation rate factor of 5.69×10^{-4} Ci/day-acre is produced, assuming a 2-ft earth cover and an ash depth of at least 10 ft. This factor must be adjusted downward according to the amount of non-ash waste, e.g., scrubber sludge, in the solid waste piles.

Because radium-226 decays to radon-gas at a very slow rate (the half-life of radium-226 is over 1600 years), it can be assumed that, over the 30-yr plant life, radon gas emanation is directly proportional to the waste pile surface area and the amount of ash containing radium-226 in the waste; therefore,

$$\text{Radon gas, Ci/day} = \left(\frac{\text{ash content in solid waste}}{\text{total solid waste disposed}}\right)\left(\text{surface area of waste piles, acres}\right) \times (\text{radon emanation factor})$$

For item 20, Solid Waste Handling, the total area necessary for the disposal of solid wastes at a depth of 30 ft over the 30-yr lifetime for the typical 500-MWe plant, assuming an 80-percent capacity factor, is 370 acres. Therefore, the average daily radon emission from the burial site over the 30-yr plant life is as follows:

$$\text{Radon gas} = \left(\frac{431\ \text{tons/day}}{1100\ \text{tons/day}}\right)\left(\frac{370\ \text{acres}}{2}\right)\left(5.69 \times 10^{-4}\ \text{Ci/day-acre}\right) = 4.1 \times 10^{-2}\ \text{Ci/day}$$

The factor of 2 is used to compute the average area of the solid waste burial ground assuming a constant buildup at 10 acres/yr over 30 yr (see item 20, Solid Waste Handling).

Therefore, the annual average radon emission, assuming a 80-percent capacity factor, is

$$\boxed{\begin{aligned}\text{Annual radon gas} &= (4.1 \times 10^{-2}\ \text{Ci/day})(365\ \text{days/yr})\\ &= 14.9\ \text{Ci/yr}\end{aligned}}$$

There are no current regulations controlling the release of radon from coal waste storage piles.

References

1. P.P. Leo and J. Rossoff, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact," EPA-600/7-78-044b, Aerospace Corporation, March 1978.
2. R.B. Fling et al., "Disposal of Flue Gas Cleaning Wastes: EPA Shawnee Field Evaluation - Third Annual Report," EPA-600/7-80-011, Aerospace Corporation, January 1978.
3. V.E. Swanson, "Collection, Chemical Analysis, and Evaluation of Coal Samples," USGA Open File Report 76-468, 1975.
4. M.I. Goldman, "Energy: What About the Waste?" Chemical Engineering Progress, November 1979, p. 65.

㉑ Makeup Water for SO_2 Control

The amount of makeup water required for flue gas desulfurization is 300 x 10^6 gal/yr.

For this analysis, a lime/limestone slurry is used in the scrubber, and it is assumed that the flue gas is saturated with water vapor upon leaving the scrubber. Typical conditions at this location are P = 15.056 psia and T = 102°F, which correspond to flue gas containing 0.127 mole water/mole dry gas. If the fractional weights of carbon (C), sulfur (S), hydrogen (H), oxygen (X), and water (W) in the coal are known, and 15 percent excess air is assumed, it can be shown that the makeup water requirement per unit weight of coal is given by the following relation:[1,2]

$$\frac{\text{lb makeup water}}{\text{lb coal}} = 12.8\left(\frac{C}{12} + \frac{S}{32}\right) + 10.5\left(\frac{H}{4} - \frac{X}{32}\right) - W - \frac{H}{9}$$

Using the coal feed rate obtained previously, the above equation can be modified to give the required daily water feed rate, W^1_{FGD}:

$$W^1_{FGD},\ \text{gal/day} = \left|12.8\left(\frac{C}{12} + \frac{S}{32}\right) + 10.5\left(\frac{H}{4} - \frac{X}{32}\right) - W - \frac{H}{9}\right|\left(2.88 \times 10^3\ \frac{P\dot{Q}}{Q}\right)$$

In addition to leaving with the flue gas, there is also going to be some water leaving with the solid wastes, e.g., $CaSO_3 \cdot \frac{1}{2}H_2O$ and $CaSO_4 . 2H_2O$. It is to be noted that, for the purposes of these calculations, the amount of water of hydration is considered negligible. The amount of water leaving in the solid wastes is a function of the sulfur concentration of coal and the slurry concentration,[1,2] i.e.,

$$\frac{\text{lb makeup water}}{\text{lb sulfur}} = 5.9\left(\frac{1-m}{m}\right)$$

where

m = weight fraction of solids in waste

= (weight of solids)/(weight of solids plus water)

The above equation can similarly be modified to give the required daily water feed rate, W^2_{FGD}:

$$W^2_{FGD},\ \text{gal/day} = 1.7 \times 10^4\ \frac{P\dot{Q}}{Q}\ S\left(\frac{1-m}{m}\right)$$

The total required daily water feed rate is therefore given as

$$W_{FGD} = W_{FGD}^{1} + W_{FGD}^{2}$$

For the typical plant, application of the above equations gives

$$W_{FGD}^{1} = 0.80 \times 10^{6} \text{ gal/day (vaporized)}$$
$$W_{FGD}^{2} = 0.23 \times 10^{6} \text{ gal/day (50 percent solids)}$$
$$W_{FGD} = 1.0 \times 10^{6} \text{ gal/day}$$

On an annual basis,

$$W_{FGD} = (1.0 \times 10^{6} \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 300 \times 10^{6} \text{ gal/yr}$$

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 40-44.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 110-120.

㉒ Lime/Limestone Requirement for SO_2 Control

The amount of lime/limestone required for flue gas desulfurization is 146 x 10^3 tons of dry $CaCO_3$/yr. (The requirement is given solely in terms of limestone because of the relatively large economic penalty incurred if lime is purchased rather than obtained during calcination of limestone.)

For limestone scrubbing, absorbent utilization is generally 0.8[1] (i.e., the calcium-to-sulfur ratio is 1.25) and, as shown in item 23, Flue Gas, Figure 2, the scrubber has to achieve 88-percent removal efficiency to satisfy the SO_2 emission standard. The limestone requirement is therefore given by

Limestone = (1.25)(100/64)(SO_2 feed rate)(scrubber efficiency)
= 1.25 (100/64)(292 ton SO_2/day)(0.88)
= 500 tons dry $CaCO_3$/day

where

100/64 = limestone/SO_2 molecular weight ratio.

On an annual basis,

Limestone = (500 tons/day)(0.8 capacity factor)(365 days/yr)
= 146 x 10^3 tons/yr

Reference

1. Aerospace Corporation, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-044b, March 1978.

㉓ Flue Gas

The pollutants and trace elements that are part of the flue gas emitted to the ambient atmosphere past control are as follows:

SO_2	10.2×10^3 tons/yr
NO_x	10.2×10^3 tons/yr
TSP	0.5×10^3 tons/yr
HC	0.22×10^3 tons/yr
CO	0.72×10^3 tons/yr
CO_2	3.7×10^6 tons/yr
As	225 lb/yr
Be	9.3 lb/yr
Cd	4.1 lb/yr
Mn	161 lb/yr
Pb	114 lb/yr
Se	56 lb/yr
Ra	3×10^{-3} Ci/yr (radioactive)

SO_2

The amount of SO_2 emitted to the ambient atmosphere is 0.6 lb/10^6 Btu. The current New Source Performance Standards for SO_2 regulation are summarized below.[1]

Uncontrolled Emissions (lb $SO_2/10^6$ Btu)	Percent Reduction	Controlled Emissions (lb $SO_2/10^6$ Btu)
> 12	> 90	1.2 maximum
12 to 6	90	1.2 → 0.6
6 to 2	90 → 70	0.6 (constant)
< 2	70	< 0.6

Basically, for steam coals burned by utilities with uncontrolled emissions exceeding 12 lb $SO_2/10^6$ Btu, SO_2 reductions exceeding 90 percent would be required to limit emissions to a maximum of 1.2 lb $SO_2/10^6$ Btu. For those coals whose uncontrolled emissions would range from 12 to 6 lb/10^6 Btu, a constant 90-percent removal is required, resulting in controlled emissions ranging from 1.2 lb $SO_2/10^6$ Btu to 0.6 lb/10^6 Btu. For coals with sulfur contents that would emit 6 to 2 lb $SO_2/10^6$ Btu, a variable removal rate between 90 and 70 percent is required to achieve a constant 0.6 lb $SO_2/10^6$ Btu. For example, at 6 lb $SO_2/10^6$ Btu, 90-percent removal is required; at

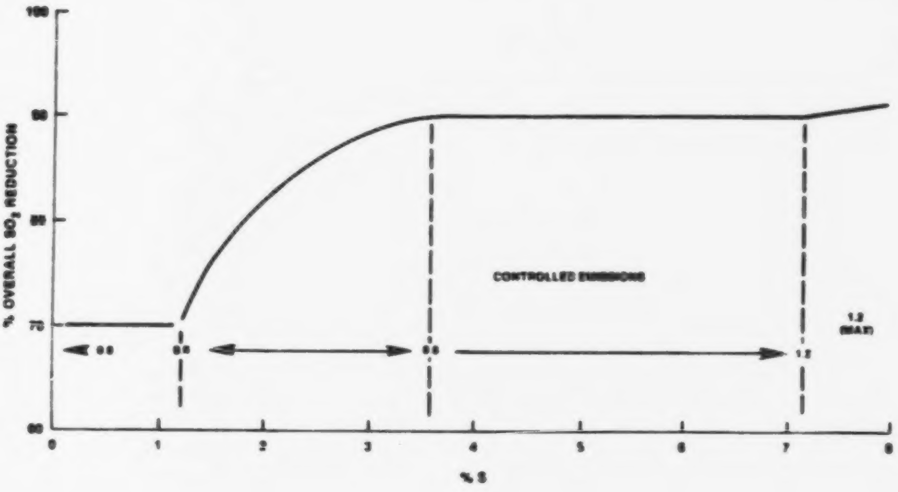
2 lb $SO_2/10^6$ Btu, 70 percent is required; and at 3 lb $SO_2/10^6$ Btu, 80 percent is needed. In all cases, it should be noted that the controlled emissions are 0.6 $lb/10^6$ Btu. If the uncontrolled emissions are less than 2 $lb/10^6$ Btu, 70 percent SO_2 is then required.

On a yearly basis, controlling SO_x and NO_x to 0.6 $lb/10^6$ Btu gives (at 80-percent capacity factor),

$$
\begin{aligned}
SO_x \text{ (and } NO_x) &= (0.6 \text{ lb}/10^6 \text{ Btu})(34 \times 10^{12} \text{ Btu/yr}) \\
&= 20.4 \times 10^6 \text{ lb/yr} \\
&= 10.2 \times 10^3 \text{ tons/yr}
\end{aligned}
$$

The SO_2 removal requirements for a 12,000 Btu/lb coal are illustrated in Figure 2. Seventy percent SO_2 removal is required up to a sulfur content of 1.2 percent. Between 3.6 and 7.2 percent, 90-percent removal is required. If the sulfur content is in the range between 1.2 and 3.6, different removal rates, as shown, are required to maintain the 0.6 lb $SO_2/10^6$ allowable. For the coal used in this ECIR (3.3 percent sulfur and 12,000 Btu/lb), an overall 89.1-percent SO_2 removal is needed. With a total of 10 percent sulfur removed as a result of pyrite removal in the coal pulverizer and as sulfur retained in the bottom ash and fly ash, the sulfur content as seen by the scrubber is 3.0 percent (3.3 - 0.1 x 3.3). The scrubber will therefore be required to remove 88 percent to achieve the overall 89.1-percent reduction.

Figure 2. Overall SO_2 Reduction Required for a 12,000 Btu/lb Coal to Meet Current NSPS Regulations



$\underline{NO_x}$

The current New Source Performance Standard for NO_x regulations is[1] 0.6 lb/10^6 Btu.

The amount of NO_x emitted to the ambient atmosphere is 0.6 lb/10^6 Btu. The general way of achieving compliance with NO_x emissions is to employ combustion modification techniques.[2,3] The boiler manufacturer usually includes in his performance guarantee the provision that emissions of nitrogen oxides while firing coal shall be less than 0.6 lb/10^6 Btu.[4] Emissions of oxides of nitrogen are limited by low flame and furnace temperatures, by short residence time of the gases at high temperatures, and by reduced amounts of excess air present in the flame.

Particulates

The current New Source Performance Standard for particulate regulation is 0.03 lb/10^6 Btu.

The amount of particulates (i.e., fly ash that is not captured in the electrostatic precipitator) emitted to the ambient atmosphere is 0.03 lb/10^6 Btu. The amount of ash in the coal used in this ECIR is 8.8 percent. If 80 percent of the ash is emitted as fly ash and the electrostatic precipitator efficiency is 99.5 percent, the particulate emission to the atmosphere is given by

$$\boxed{\begin{aligned}\text{Particulates} = {} & \text{(ash fraction in coal)(fly ash fraction)(coal feed rate)}\\ & \text{(1-electrostatic precipitator efficiency)}\end{aligned}}$$

For the typical plant,

$$\boxed{\begin{aligned}\text{Particulates} &= (0.088)(0.80)(4.9 \times 10^3 \text{ tons/day})(1-0.995)\\ &= 1.7 \text{ tons/day}\end{aligned}}$$

On a yearly basis,

$$\boxed{\begin{aligned}\text{Particulates} &= (1.7 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})\\ &= 500 \text{ tons/yr}\end{aligned}}$$

On a yearly basis, controlling particulates (TSP) to 0.03 lb/10^6 Btu gives (at 80-percent capacity factor),

$$\boxed{\begin{aligned}\text{TSP} &= (0.03 \text{ lb}/10^6 \text{ Btu})(34 \times 10^{12} \text{ Btu/yr})\\ &= 1.02 \times 10^6 \text{ lb/yr}\\ &= 500 \text{ tons/yr}\end{aligned}}$$

Carbon Monoxide and Hydrocarbons

There are no New Source Performance Standards for carbon monoxide (CO) or hydrocarbons (HC). The amounts of CO and HC emitted to the ambient atmosphere are 2.45 tons/day and 0.74 ton/day, respectively. The emission factors for CO and HC are 1 lb/ton coal burned and 0.3 lb/ton coal burned, respectively.[5] Hence, the daily emissions of these pollutants are given by

$$\boxed{\text{CO, HC} = (\text{emission factor})(\text{coal feed rate})}$$

For the typical plant,

$$\text{CO} = (1\ \text{lb/ton})(4.9 \times 10^3\ \text{tons/day})/2 \times 10^3\ \text{lb/ton}$$
$$= 2.45\ \text{tons/day}$$

$$\text{HC} = (0.3\ \text{lb/ton})(4.9 \times 10^3\ \text{tons/day})/2 \times 10^3\ \text{lb/ton}$$
$$= 0.74\ \text{ton/day}$$

On a yearly basis,

$$\text{CO} = (2.45\ \text{tons/day})(0.8\ \text{capacity factor})(365\ \text{days/yr})$$
$$= 720\ \text{tons/yr}$$

$$\text{HC} = (0.74\ \text{tons/yr})(0.8\ \text{capacity factor})(365\ \text{days/yr})$$
$$= 220\ \text{tons/yr}$$

An indication of the completeness of a combustion process is the concentration of carbon monoxide (and, to a lesser extent, hydrocarbon concentration). As such, pulverized coal-fired boilers have negligible emissions of carbon monoxide and hydrocarbons. Careful monitoring of excess air and temperature in the boiler ensures that the emissions of these pollutants are low.[6]

Trace Elements

Atmospheric emission rates for the trace elements are calculated to be (see Appendix C, Trace Element Analysis)

Element	lb/day at 100% capacity factor	lb/yr at 80% capacity factor
As	0.77	225
Be	0.03	9.3
Cd	0.01	4.1
Mn	0.55	161
Pb	0.39	114
Se	0.19	56

The trace elements are species found in small quantities in the raw coal. They become distributed among the bottom ash slag or the fly ash and flue gases. In the latter, some are emitted past the precipitator and enter the atmosphere. Because many trace elements exhibit preferential concentrations in the smaller particles emitted, about 5 percent of the initial concentrations of most trace elements are emitted to the ambient atmosphere.[7] Based on recent work at Lawrence Livermore Laboratory, a method was developed to calculate trace element emissions to the atmosphere. The generalized methodology, algorithm, and associated references for calculating trace element emissions are given in Appendix B.

Carbon Dioxide

The amount of CO_2 emitted to the ambient atmosphere is 12.5×10^3 tons/day. During the combustion of bituminous coal, 0.21 lb CO_2 are emitted to the atmosphere for every 10^3 Btu generated.[8] Hence,

$$(CO_2)_{COMB} = \text{(emission factor)(coal feed rate)(heat content of coal)}$$

For the typical plant,

$$\begin{aligned}(CO_2)_{COMB} &= (0.21\ \text{lb}/10^3\ \text{Btu})(4.9 \times 10^3\ \text{tons/day})(12 \times 10^3\ \text{Btu/lb}) \\ &= 12.3 \times 10^3\ \text{tons/day}\end{aligned}$$

Additionally, a small amount of CO_2 is released to the atmosphere from the limestone reaction with the SO_2.[9] This amount is estimated as follows:

$$\begin{aligned}(CO_2)_{LIMESTONE} &= \left(\begin{array}{c}\text{500 tons/day, limestone into} \\ \text{scrubber}\end{array}\right)\left(\frac{44}{100}, \begin{array}{c}\text{molecular weight} \\ \text{of } SO_2/CaCO_3\end{array}\right) \\ &= 0.220 \times 10^3\ \text{tons/day}\end{aligned}$$

The total amount of CO_2 emitted to the atmosphere is given by

$$\begin{aligned}CO_2 &= (CO_2)_{COMB} + (CO_2)_{LIMESTONE} \\ &= 12.3 \times 10^3\ \text{tons/day} + 0.22 \times 10^3\ \text{tons/day} \\ &= 12.5 \times 10^3\ \text{tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}CO_2 &= (12.5 \times 10^3\ \text{tons/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 3.7 \times 10^6\ \text{tons/yr}\end{aligned}$$

Radionuclides

Analysis of the fly ash produced by combustion of eastern bituminous coal has shown that a typical 500-MWe plant will discharge into the atmosphere approximately 10.35×10^{-6} Ci/day of radioactive radium (Ra).

Because over 80 percent of the trace radioactive particles in coal remain with the fly ash after combustion, removal of the fly ash by electrostatic precipitators is the most effective control technology available.[10] Samples from the combustion of six different batches of Appalachian coal were analyzed for its radium content by Eisenbud and Petrow with the following results:[10]

Concentration of Radioactive Elements in Fly Ash

Radium-226	3.8×10^{-12} Ci/gm	or	1.73×10^{-9} Ci/lb
Radium-228	2.4×10^{-12} Ci/gm		1.09×10^{-9} Ci/lb

Other trace radioactive elements are emitted, e.g., thorium and uranium, but pose a much smaller health hazard than radium.

Assuming the total activity released to the environment is through the fly ash escaping the electrostatic precipitators, the daily release of any radioactive isotope may be calculated as follows:

$$\text{Activity of isotope i, Ci/day} = (\text{concentration of isotope i in fly ash})(\text{fly ash generated, tons/day})(2000\ \text{lbs/ton})(1-\text{ESP}_{\text{EFFICIENCY}})$$

For the typical plant,

$$\begin{aligned}\text{Radium-226} &= (1.73 \times 10^{-9}\ \text{Ci/lb})(367\ \text{tons/day})(2000\ \text{lbs/ton})(1-.995)\\ &= 6.35 \times 10^{-6}\ \text{Ci/day}\\ \text{Radium-228} &= (1.09 \times 10^{-9}\ \text{Ci/lb})(367\ \text{tons/day})(2000\ \text{lbs/ton})(1-.995)\\ &= 4.00 \times 10^{-6}\ \text{Ci/day}\end{aligned}$$

Total radium activity emitted daily for the typical plant is therefore 10.35×10^{-6} Ci/day.

On a yearly basis,

$$\begin{aligned}\text{Radium} &= (10.35 \times 10^{-6}\ \text{Ci/day})(0.8\ \text{capacity factor})(365\ \text{days/yr})\\ &= 3 \times 10^{-3}\ \text{Ci/yr}\end{aligned}$$

To date, there are no regulations that apply to the release of radioactive pollutants from coal-fired power plants.

References

1. Federal Register, Vol. 44, No. 113, 40 CFR Part 60, "New Sources Performance Standards; Electric Utility Steam Generating Units," June 11, 1979.
2. J. Ando, "NO_x Abatement for Stationary Sources in Japan," EPA-600/7-79-205, August 1979.
3. National Academy of Sciences, "Air Quality and Stationary Source Emission Control," prepared for the Committee on Public Works, U.S. Senate, Serial No. 94-4, 1975.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978.
5. U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," 2nd edition, EPA AP-42, 1975.
6. Final Environmental Impact Statement, Spurlock Station, Unit No. 2 and Associated Transmission, USDA-REA-EIS-76-4F, November 1976.
7. K.K. Bertin and E.D. Goldbert, Science, Vol. 183, p. 233, 1971.
8. U.S. Department of Energy, "CO_2 Emissions from Synthetic Fuels Energy Sources," August 8, 1979, p. 2, Table 1.
9. Aerospace Corporation, Estimation, April 1980.
10. M. Eisenbud and H.G. Petrow, "Radioactivity in the Atmospheric Effluents of Power Plants That Use Fossil Fuels," Science 144, April 17, 1964, p. 288

III. PHYSICAL REQUIREMENTS

Large amounts of land and water resources are required for a coal-fired power plant. The section on Water summarizes the requirements and uses of makeup water discussed in Section II. The section on Land discusses the land needed for plant siting and solid waste disposal.

Water

The maximum makeup water requirement estimated for the typical plant operating at 80-percent capacity factor is 2.7 x 10^9 gal/yr. Some of this water is recovered, treated in the water treatment facility, and recycled back to the plant (see Section II, item ⑯, Recycle Water). The remainder is obtained from local water sources and is lost primarily through evaporation and drift losses in the cooling towers, holding pond surface losses, and dust suppression systems. The major uses of makeup water are listed in Table 2.

Table 2. Makeup Water Demands for Major Plant Processes (at 80-Percent Capacity Factor)

Source	Environmental Point of Interest on Flow Chart	Estimated Quantity (gal/yr)
Cooling tower makeup	11	2.2 x 10^9
SO_x control	21	300 x 10^6
Generating plant makeup	13	180 x 10^6
Electrostatic precipitator fly ash transport	18	24 x 10^6
Total estimated makeup water demand	-	≈2.7 x 10^9
Recovered Water for Recycling		
Controlled runoff from coal storage	7	Variable
Boiler blowdown and miscellaneous plant drains	12	175 x 10^6
Cooling tower blowdown	10	200 x 10^6
Water removed from solid waste handling system	20	Variable
Total estimated recycled water available for makeup	16	≈29 x 10^6
Net makeup water requirements	-	2.67 x 10^9
Total estimated makeup water demand	-	2.7 x 10^9
Total estimated availability of recycled water	-	29 x 10^6

Land

The sizes of actual power plant sites vary over a considerable range and depend on a number of factors such as utility preference, cost of land, onsite versus offsite waste disposal, plant location, and the power of the plant. Although there is not a strong link between site size and the particular features of the plant (such as MWe), broad relationships exist. For plants in the 500-MWe range, site sizes appear to vary from about 500 to 1000 acres. There are a number of older plants sited in urban areas with much smaller sites, but they should not be considered typical for new plants.

Because the land needed for buildings is a relatively small portion of the site, the bulk of the site is needed for coal storage, onsite waste disposal (ponds, etc.), and general working room. Solid waste disposal area for a plant similar to the typical plant was estimated at 370 acres (30-ft depth) for the 30-yr lifetime of the plant (see Section II, item ⑳, Solid Waste Handling).[1] A representative 500-MWe plant that does not have onsite solid waste disposal for the entire life of the plant has a site size of approximately 400 acres, excluding waste disposal.[2] Accordingly, 800 acres is a typical site size when lifetime waste disposal is included.

The typical plant was designed as a mine-mouth plant with its own coal preparation plant. The actual coal preparation facilities would require a minimum of 1.5 acres.[3] In addition, if the refuse from the preparation plant is kept aboveground, disposal area will be required. The preparation plant will generate 1800 tons/day of refuse (see Section II, item ④, Solid Waste From Coal Preparation, for calculation). Assuming a density of 50 lb/ft^3, and a 30-ft depth, the land requirements for waste disposal are calculated as follows:

$$\text{Land requirements, acres/yr} = \frac{0.34\ (\text{solid waste disposal, tons/day})}{\text{depth of disposal site, ft}}$$

For the typical plant,

$$\begin{aligned} \text{Land} &= \frac{0.34\ (1800\ \text{tons/day})}{30\ \text{ft}} \\ &= 20.4\ \text{acres/yr (at 100-percent capacity factor)} \\ &= (20.4)(0.8) \\ &= 16\ \text{acres/yr (at 80-percent capacity factor)} \end{aligned}$$

For the 30-yr lifetime of the plant, the land required for coal preparation waste disposal is therefore approximately 500 acres.

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA-450/2-78-007a, pp. 6-18, July 1978.
2. Final Environmental Impact Statement, Spurlock Station Unit No. 2, and Associated Transmission, USDA-REA-EIS-76-4F, November 1976, p. 69.
3. Personal Communication, Phillip Halch, Roberts and Schaefer Engineers and Contractors, April 1980.

IV. PERSONNEL

Although the number of people required for the operation and planned maintenance of a power plant is highly dependent on the philosophy of the particular utility, certain standards are used. One such guideline is 0.089 persons/MWe for each shift.[1] This number, which includes support personnel and personnel for operating and maintaining pollution control equipment, equates to 45 persons per shift or 135 persons total per day for a 500-MWe plant.

In addition to the above requirement, personnel will be needed for the coal preparation plant. Although preparation plant staffing levels vary, discussions with power engineers revealed that 10 persons per shift or 20 persons total for the two preparation plant shifts would be a reasonable figure.

Reference

1. Personal Communication, John W. Holt, Jr., Power Plants Branch, Rural Electrification Administration, Washington, D.C., April 1980.

V. OCCUPATIONAL SAFETY AND HEALTH

Occupational safety and health implications of coal-fired power plants have been examined using actual death and injury statistics.[1] For coal processing plants, the report lists (per 10^8 tons processed) 1.7 to 2.7 deaths and 98 to 159 injuries. The corresponding figures for power plant workers (per 10^{12} Btu output) are 0 to 0.0095 deaths and 0.16 to 0.19 injuries.

For the plant assumed in this ECIR, the amount of coal processed is 1.96 x 10^6 tons/yr and 0.16 x 10^6 tons/10^{12} Btu. The output of the plant is 12 x 10^{12} Btu/yr. Thus, the projected deaths and injuries for the plant are as follows:

	Preparation Plant		Power Plant	
	Annual	Per 10^{12} Btu	Annual	Per 10^{12} Btu
Deaths	0.0033-0.0053	0.0003-0.0004	0-0.11	0-0.0095
Injuries	1.9-3.1	0.16-0.26	1.9-2.3	0.16-0.19

Reference

1. S.C. Morris, K.M. Novak, and L.D. Hamilton, "Health Effects of Coal in the National Energy Plan," Brookhaven National Laboratory, BNL-51043, April 1979, pp. 8-9.

APPENDIX A. AIR EMISSIONS UNDER VARIOUS REGULATORY AND CONTROL TECHNOLOGY ASSUMPTIONS

The air emissions calculated for the coal-fired power plant described in this document are based on current Federal NSPS for coal-fired power plants using bituminous coal and that commenced construction after September 18, 1978. The units coming on line now and for several years into the future are generally subject to the previous Federal NSPS. There are also many units now operating that were under constructon or operating prior to the effective date of the previous NSPS and are therefore not subject to any Federal NSPS. Although these plants are subject to Federal NSPS less stringent than the current regulation, they will in many instances be subject to more stringent state and local air emission regulations. In many instances, the new plants, subject to current Federal NSPS, will also be subject to more stringent state or local standards that will effectively establish the allowable air pollutant emission levels. Table A-1 provides a summary of air emissions under current NSPS and previous NSPS, as well as emissions from uncontrolled plants.

It should also be noted that under the previous NSPS and uncontrolled assumptions, coals having low-sulfur content could be used to reduce SO_2 emissions and to thus comply with the NSPS standard. The new NSPS do not allow the use of low-sulfur coal alone as an SO_2 control for new plants.

In addition to impacts on air emissions, the use of a limestone or lime scrubber generates a varying amount of solid waste (scrubber sludge). As SO_2 removal requirements increase, the amount of scrubber sludge will increase (see item ⑲, Sludge From SO_2 Control). Solid wastes will also be increased if a higher ash coal is selected (see item ⑰, Fly Ash From Particulate Control).

Table A-1. Air Emissions Under Various Regulatory Assumptions*

Federal Regulation	Firing Rate - 34×10^{12} Btu/yr SO_2	 NO_x	 Particulate
Current NSPS As of 6/11/79	.6 lb/10^6 Btu 10.2×10^3 tons/yr	.6 lb/10^6 Btu 10.2×10^3 tons/yr	.03 lb/10^6 Btu $.50 \times 10^3$ tons/yr
Previous NSPS 12/23/71 to 6/11/79	1.2 lb/10^6 Btu 20.4×10^3 tons/yr	.7 lb/10^6 Btu 11.9×10^3 tons/yr	.1 lb/10^6 Btu 1.7×10^3 tons/yr
Uncontrolled emissions	85×10^3 tons/yr	**"Normal firing" @ .82 lb/10^6 Btu 13.9×10^3 tons/yr	50% mechanical removal of fly ash 50×10^3 tons/yr

* Based on the plant assumed in this ECIR, using a coal with 3.3 percent sulfur content.

** U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978, p. 6-9.

APPENDIX B. COST INFORMATION

Obtaining an accurate estimate of the costs associated with any power plant is an ambitious undertaking and beyond the scope of this study. However, sufficient information is available to approximate the costs for the typical plant.

An extensive effort by the Department of Energy (DOE) and the Nuclear Regulatory Commission (NRC)[1] examined the total costs (capital, fuel, and operating and maintenance) for various plant types and sizes under a range of economic assumptions. The plant most similar to the typical plant in this Environmental Characterization Information Report (ECIR) is a 794-MWe plant burning high-sulfur coal. It, too, is a pulverized coal plant with electrostatic precipitator and flue gas scrubbers.

There is sufficient information in the study to determine approximate economies of scale with respect to plant size. When the data for the 794-MWe plant are converted to our 500-MWe plant size, the result for plant capital cost is $450/kW (1976 dollars) or $225,000,000. The DOE/NRC study provided an analysis that assumed an 8-percent escalation rate and a 1985 date for first operation. Under these assumptions, correcting for escalation, interest during construction, and contingency, the total (integrated) capital cost for the 500-MWe plant is $1270/kW, or $635,000,000. If the escalation rate were only 5 percent, the capital cost would be $1030/kW, or $514,000,000.

The study also calculated the total costs for the 1985 plant in mills/kWh (including capital, fuel, and operating and maintenance), assuming 8-percent escalation and a 12-percent discount rate, as well as the alternate economic assumptions of 5-percent escalation and 10-percent discount rate. As might be expected, this total cost will depend on the portion of time the plant actually operates (capacity factor). The total costs for the 500-MWe plant are as follows:

	Total Generating Costs (mills/kWh)	
Capacity Factor (%)	8% Escalation 12% Discount	5% Escalation 10% Discount
50	116.9	87.4
60	107.4	78.8
70	101.1	72.8
80	96.0	68.1

These cost figures include transportation of coal 900 miles from the eastern high-sulfur coal mines to a hypothetical northeastern coastal location. If coal transportation were not necessary, as in the case of the mine-mouth typical plant, the total generating costs would be reduced by 23.6 mills/kWh for the 8-percent escalation/12-percent discount case and 13.8 mills/kWh for the 5-percent escalation/10-percent discount case. Thus, the costs for the typical plant, excluding coal preparation, are as follows:

	Total Generating Costs (mills/kWh)	
Capacity Factor (%)	8% Escalation 12% Discount	5% Escalation 10% Discount
50	93.3	73.6
60	83.8	65.0
70	77.5	59.0
80	72.4	54.3

The capital cost for the coal preparation plant is estimated at $10.5 million in 1976 dollars, with operating and maintenance costs of $1.33/ton of coal.[2] This total cost for the coal preparation plant, which is not very sensitive to the capacity factor, is 5.8 mills/kWh for the 8-percent escalation/12-percent discount case and 3.9 mills/kWh for the 5-percent escalation and 10-percent discount case.

References

1. United Engineers and Constructors, Inc., "Total Generating Cost: Coal and Nuclear Plants," Vol. 8 in a Series of 8 Commercial Electric Power Cost Studies, NUREG-0248, COO-2477-12, February 1979.
2. J.F. Wilkinson, ed., "What's New in Preparation: Equipment, Processes, and Training," Coal Age, Vol. 85, No. 1, pp. 54-109, January 1980.

APPENDIX C. TRACE ELEMENT ANALYSIS

Trace elements are species that are found in small quantities in a mineral. During coal combustion, they become distributed among slag, fly ash, or gases and are emitted into the environment. Based on industrial experience with pulverized coal boilers, it is generally accepted that 80 percent of the ash present in coal is charged as fly ash, while only 20 percent is discharged as bottom ash.[1,2] Because many trace elements exhibit preferential concentrations in the smaller particles emitted from coal-fired power plants,[3-6] about 5 percent of the initial concentrations of most trace elements are emitted to the ambient atmosphere.[7] In addition, due to the nonhomogeneity of coal, the composition and concentration of combustion products will vary with coal. However, based on recent work conducted by Lawerence Livermore Laboratory, it is possible to calculate trace element emissions if certain system operating parameters and coal composition are known.[8] An explanation of how this is done follows.*

Needed information:

- Trace element concentrations in coal being fired (C_i, $i=1, 2, \ldots n$, µg/g)
- Coal feed rate (F, g/sec)
- Plant net power output (P, watts)
- Overall thermal efficiency (η_p)
- Electrostatic precipitator overall efficiency (η_{ESP})

Definitions:

plant total power input = (plant net power output)/(overall thermal efficiency)

= P/η_p

(consumption rate)$_i$ = (trace element i concentration in coal) (coal feed rate)/(plant total power input)**

= $(C_i)(F)/P/\eta_p)$

ESP efficiency ratio = (1-ESP overall efficiency)/(1-ESP overall efficiency used in LLL study)

= $(1-\eta_{ESP})/(1-0.97)$

---

* There are other methodologies for determining trace element emissions; see, for example, Reference 7.

** Note: 1 watt = 1 joule/second.

$(\text{atmospheric emission rate})_i$ = (stack emission of trace element i)/(plant total power input)

$(\text{AER})_i$ = unknown to be determined

$(\text{penetration})_i$ = (100%) $(\text{atmospheric emission rate})_i/(\text{consumption rate})_i$

= given in following Table C-1

Procedure:

1. When the needed information is obtained, determine

    - plant total power input
    - $(\text{consumption rate})_i$
    - ESP efficiency ratio

2. Obtain $(\text{penetration})_i$ from Table C-1

3. $(\text{atmospheric emission rate})_i = (\text{penetration})_i(\text{consumption rate})_i(\text{ESP efficiency ratio})/100$

$$\boxed{(\text{AER}, \mu g/\text{joule})_i = (\text{penetration})_i\ [(C_i)(F)/(P/\eta_p),\ \mu g/\text{joule}]\ (1-\eta_{ESP})/[(1-0.97)]}$$

For the typical plant a representative coal from Kentucky was chosen.[10] Trace element concentrations of this coal are listed as follows:

Element	Concentration ($\mu g/g$)
As	4.1
Be	2.2
Cd	0.1
Mn	21.0
Pb	4.3
Se	1.5

To find the atmospheric emission rates for the trace elements, the following information is used:

$P = 500 \times 10^6$ watt
$\eta_p = 35$ percent
$F = 51.5 \times 10^3$ g/sec
$\eta_{ESP} = 99.5$ percent

Table C-1. **Penetration of Elements Contained in Particles Emitted From an ESP-Equipped Coal-Fired Generating Unit (%)**

Element	ESP Unit[a]	Element	ESP Unit[a]
Al	1.1 ± 0.1	Mo	5.1 ± 1.2
As	11.5 ± 3.0	Mn	1.6 ± 0.5
Ba	4.0 ± 0.8	Na	1.55 ± 0.09
Be	0.9 ± 0.3	Pb	5.5 ± 1.1
Br	0.14 ± 0.08	Rb	1.3 ± 0.1
Ca	1.3 ± 0.2	Sb	7.7 ± 0.7
Cd	8.8 ± 3.0	Sc	1.46 ± 0.06
Ce	1.29 ± 0.09	Se	7.7 ± 0.8
Co	2.5 ± 0.3	Sr	2.0 ± 0.3
Cr	3.8 ± 0.3	Ta	1.3 ± 0.1
Cs	1.2 ± 0.2	Th	1.32 ± 0.08
Fe	1.32 ± 0.09	Ti	1.51 ± 0.03
Ga	4.4 ± 0.7	U	3.7 ± 0.4
In	5.4 ± 0.7	V	3.7 ± 0.6
K	1.0 ± 0.3	W	7.2 ± 2.2
La	1.29 ± 0.07	Zn	6.3 ± 0.8
Mg	1.2 ± 0.4	Zr	1.4 ± 0.3

---

[a] Number of samples was eight unless otherwise indicated.

The atmospheric emission rate for arsenic is therefore

$$
\begin{aligned}
(\mathrm{AER})_{\mathrm{As}} &= \left|\frac{(\text{penetration})_{\mathrm{As}}\,(C_{\mathrm{As}})(F)}{(P/n_p)}\right|\left|\frac{1-\mathrm{ESP}}{1-0.97}\right| \\
&= \left|\frac{(0.115)(4.1\ \mu g/g)(51.5 \times 10^3\ g/s)}{500 \times 10^6\ J/s\,/\,0.35}\right|\left|\frac{1-0.995}{1-0.97}\right| \\
&= 2.83 \times 10^{-6}\ \mu g/J
\end{aligned}
$$

On a daily basis,

$$
\begin{aligned}
(\mathrm{AER})_{\mathrm{As}} &= \frac{(2.83 \times 10^{-6}\ \mu g/J)(1.055 \times 10^3\ J/Btu)(0.117 \times 10^{12}\ Btu/day)(1 \times 10^{-6}\ g/\mu g)}{(0.454 \times 10^3\ g/lb)} \\
&= 0.77\ lb/day
\end{aligned}
$$

Daily atmospheric emission rates for the trace elements are as follows:

Element	lb/day at 100% capacity factor	lb/yr at 80% capacity factor
As	0.77	225
Be	0.03	9.3
Cd	0.01	4.1
Mn	0.55	161
Pb	0.39	114
Se	0.19	56

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
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4. N.E. Bolton et al., "Trace Element Measurement at the Coal-Fired Allen Steam Plant, Progress Report, June 1971 - January 1973," ORNL-NSF-EP-43, March 1973.
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6. G.E. Gordon et al., "Study of the Emissions from Major Air Pollution Sources and Their Atmospheric Interactions," University of Maryland Department of Chemistry and Institute for Fluid Dynamics and Applied Mathematics, College Park, Maryland, 1974.
7. K.K. Bertine and E.D. Goldbert, Science, Vol. 173, No. 233, 1971.
8. J.M. Ondov, R.C. Ragaini, and A.H. Biermann, "Emissions and Particle-Size Distributions of Minor and Trace Elements at Two Western Coal-Fired Power Plants Equipped with Cold-Side Electrostatic Precipitators," Environmental Science and Technology, Vol. 13, pp. 946-953, 1979.
9. Radian Corporation, "Trace Elements of Fly Ash: Emissions from Coal Fired Steam Plants Equipped with Hotside and Coldside Electrostatic Precipitators for Particulate Control," EPA 908/4-78-008, December 1978, Final Report.
10. H.J. Gluskoter et al., "Trace Elements in Coal: Occurrence and Distribution," Illinois State Geological Survey, Circular 499, 1977.

GLOSSARY

Blowdown	Water that is periodically removed from either the cooling towers or the coal-fired boiler to prevent concentration of total dissolved solids.
Bottom ash	Noncombustible residues of coal combustion that are collected and removed from the boiler.
Capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.
Circulating water	Water supplied to the main condenser in the generating plant that is cooled by the cooling towers.
Cooling tower drift loss	Aerosols of water that are lost in the atmosphere from the cooling towers.
Cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.
Curie (Ci)	An amount of radioactive material that decays at a rate of 3.7×10^{10} disintegrations per second.
Dead storage	Long-term storage in which the coal is typically compacted and sealed.
Discount rate	A factor in formulas used for analyzing the time value of money. Its magnitude depends on the cost of capital, financing schemes, etc.
Electrostatic precipitator	Environmental control device used to remove a high percentage of the fly ash in the flue gas.
Escalation	Increases in cost of equipment, materials, labor, etc., as a result of inflation.
Flue gas	Gases generated from the combustion of fossil fuel in the boiler.
Flue gas desulfurization scrubbers	Environmental control device used to remove a high percentage of the sulfur dioxide in the flue gas.
Fly ash	Noncombustible residues of coal combustion that are carried out of the boiler in the flue gas.

Fugitive emissions	Unintentional emissions, such as blowing dust from a coal pile.
Net station heat rate (Q)	Amount of fuel input (in Btu) necessary to generate 1 kWh of electricity.
Pyritic material	Metallic compounds of sulfur naturally occurring in coal.
Recycle water	Water that is collected, treated, and reused at the power plant.
Run-of-mine coal	Coal as it comes from the mine prior to sizing or other preparation.
Sludge	Wet residue of lime/limestone and sulfur that is generated in the flue gas desulfurization unit.

ACRONYMS AND ABBREVIATIONS

A	ash content in coal
AER_i	atmospheric emission rate of trace element i
As	arsenic
Be	beryllium
Btu	British thermal unit
C	carbon
$CaSO_3$	limestone
Cd	cadmium
Ci	curie
C_i	concentration of trace element i
Cl	chlorine
CO	carbon monoxide
CO_2	carbon dioxide
Cu	copper
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
η_p	overall thermal efficiency of plant
η_{ESP}	overall efficiency of electrostatic precipitator
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
F	feed rate of coal
Fe	iron
FGD	flue gas desulfurization
g	gram
gal	gallon
H	hydrogen
ha	hectare
HC	hydrocarbons
J	joule
kg	kilogram
kWh	kilowatt-hour
l	liter
lb	pound
mg	milligram (10^{-3} gram)
μg	micrograms (10^{-6} grams)
Mn	manganese
MWe	megawatt - electrical
MWt	megawatt - thermal
N	nitrogen
NO_x	nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
O	oxygen
P	net power delivered to the transmission grid
Pb	lead
Q	heat content of coal
$\dot{Q}$	net station heat rate
ROM	run-of-mine

s	second
S	sulfur
Se	selinium
SO_2	sulfur dioxide
te	tonne
TSP	total suspended particulates (air)
TSS	total suspended solids (water)
W_{BA}	total makeup water requirements for bottom ash handling
$W_{BLOWDOWN}$	amount of cooling tower blowdown
W_{DRIFT}	amount of drift loss from cooling tower
W_{EVAP}	amount of evaporation loss from cooling tower
W_{FGD}	makeup water for dust control of SO_2 scrubbers
W_{HAD}	amount of water needed for bottom ash handling and disposal
W_{TOW}	total makeup water requirements to the cooling towers
W_{VAP}	amount of evaporation loss from bottom ash hopper

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Coal-Fired Power Plant
(Western Coal)
Environmental Characterization Information Report

January 1981

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Assistant Secretary for Environmental Protection,
Safety & Emergency Preparedness
Office of Environmental Assessments
Washington, D.C. 20585

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FOREWORD

This Environmental Characterization Information Report (ECIR) is a synthesis of environmental data and information relevant to a coal-fired power plant that burns western coal. It is prototypical of a set of ECIRs that will be developed for a range of fossil, solar, geothermal, nuclear, and conservation energy systems. The ECIRs are designed to have several related purposes: to communicate to all potential users environmental data and information characteristic of an energy system; to present an organized data and information base for application in manual and computer-based analytical systems; and to provide the medium for facilitating development, maintenance, and critical review of the data and information base. The set of ECIRs is designed to replace the general technical backup volumes formerly supplied with "Environmental Data Energy Technology Characterizations," Summary, January 1980.

Responsibility for the contents and development of an ECIR is assigned to individual technology specialists in the Technology Assessments Division. This ECIR was developed under the direction of Mr. William G. Wilson of the Fossil Energy Program staff. In this endeavor, we also draw upon the technical support and assistance of qualified external experts familiar with the energy systems. Technical comments regarding this ECIR should be directed to Mr. William G. Wilson, Project Officer, (301) 353-4414. Suggestions or recommendations for improving the ECIR concept should be addressed to me.

Dario R. Monti

Dario R. Monti
Director, Technology Assessments Division
Office of Technology Impacts

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I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Coal-Fired Power Plants (Western Coal) has been prepared from the latest available environmental and technical information collected from a number of sources. The typical plant chosen for characterization is a 500-MWe pulverized-coal plant burning western low-sulfur (<1 percent) coal. The plant uses an electrostatic precipitator, a lime/limestone scrubber, and a wet, mechanical draft cooling tower. The plant fuel is supplied from offsite mines by unit-train deliveries with surface mined, thick seam coal, which undergoes minimum preparation prior to pulverization.

The process, plant operating parameters, resources needed, and environmental residuals and products associated with the power plant are presented in this secton in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 80 percent. While this capacity factor is representative of the reliability of generating units of this size, it does not consider unscheduled shutdowns for repairs of associated environmental control equipment, boiler related outages, or factors independent of the plant itself, e.g., reserve requirements.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of electric energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Twenty-three environmental points of interest are quantified and discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions, and a bibliography of cited references. Specific environmental regulations are discussed in the individual sections. The calculations of allowable emission levels are based on current Federal regulations applicable to new plants. For information on similar sized plants operating under previous Federal regulations, see Appendix A. For information on impending regulations, see Reference 1.

Section III discusses the overall physical requirements of the plant for land and water. A glossary of terms and a trace element analysis are included as appendixes to this report.

Reference

1. U.S. Department of Energy, Office of Technology Impacts, Office of Environment, "Environmental Issues Briefing Book for Policy Analysis Division," original issue April 1979 (compiled by the Mitre Corporation).

TABLE 1. SUMMARY SHEET

COAL-FIRED POWER PLANT
(WESTERN LOW-SULFUR SUBBITUMINOUS COAL)

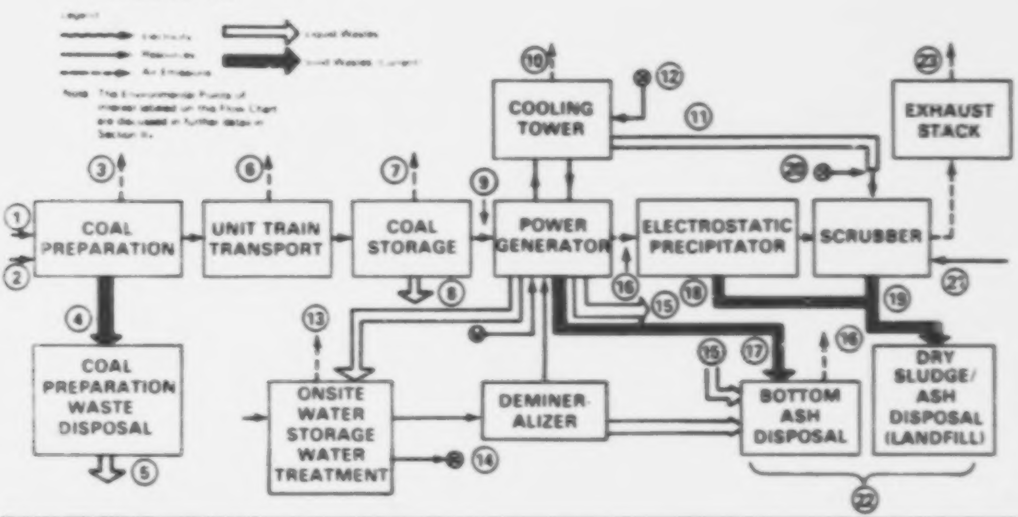
ENERGY SYSTEM DESCRIPTION

Conventional Steam Electric Power Plant Using Typical Western Low-Sulfur Subbituminous Coal Supplied by a Unit Train Operation; No Cogeneration; Electrostatic Precipitator for Particulate Control; Wet Lime/Limestone Scrubber for SO_2 Control; Onsite Solid Waste Disposal; and Onsite Water Treatment for Recirculation to Eliminate Liquid Discharges. New Plant Subject to Current Regulations.

PLANT OPERATING PARAMETERS

Power Output to Grid:	500 MWe
Annual Capacity Factor:	80% (assumed)
Overall Plant Efficiency:	35%
Annual Energy Production:	12×10^{12} Btu (12.66×10^{15} J) (3.5×10^6 MWh)
Plant Lifetime:	30 yr

PROCESS FLOW



COOLING TOWER
EXHAUST STACK
COAL PREPARATION
UNIT TRAIN TRANSPORT
COAL STORAGE
POWER GENERATOR
ELECTROSTATIC PRECIPITATOR
SCRUBBER
COAL PREPARATION WASTE DISPOSAL
ONSITE WATER STORAGE WATER TREATMENT
DEMINERALIZER
BOTTOM ASH DISPOSAL
DRY SLUDGE/ ASH DISPOSAL (LANDFILL)
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RESOURCES USED

Code No	Resource	Quantities Used: Annual Usage*: English Units	Quantities Used: Annual Usage*: Metric Units	Quantities Used: Per 10^{12} Btu Energy Produced	Remarks
	Fuel				
①	Run-of-mine western low-sulfur subbituminous coal	2.11×10^6 tons	1.92×10^6 tonnes	0.18×10^6 tons	Low-sulfur coal (0.63% S)
⑨	Coal feed to boiler	2.10×10^6 tons	1.91×10^6 tonnes	0.18×10^6 tons	
	Water				
②	Coal preparation dust control water	3.0×10^6 gal	11.4×10^6 liters	0.25×10^6 gal	Quality not critical
⑫	Cooling tower makeup water	1.6×10^9 gal	6.1×10^9 liters	0.13×10^9 gal	
⑳	SO_2 control makeup water	14.2×10^7 gal	53.7×10^7 liters	1.18×10^7 gal	
	Raw Materials for Processing				
㉑	Limestone to scrubber	32×10^3 tons	29×10^3 tonnes	2.7×10^3 tons	
⑱	Byproduct fly ash	34×10^3 tons	30.8×10^3 tonnes	2.9×10^3 tons	
	Land				
㉒	Land for power plant and environmental solid waste disposal (see Section III)	5.2 acres	2.1 ha	0.43 acre	Sufficient land needed for a 30-yr life
	Personnel				
	Power plant	135 man-yr		11.3 man-yr	
	Preparation plant	20 man-yr		1.7 man-yr	
	Raw Materials for Construction Facility Costs Control Costs	To Be Added			

*Based on the assumed 80% capacity factor

TABLE 1. (Continued)

COAL-FIRED POWER PLANT
(WESTERN LOW-SULFUR SUBBITUMINOUS COAL)

ENVIRONMENTAL RESIDUALS AND PRODUCTS

Code No.	Residual or Product	Quantities Released			Regulatory Compliance Levels
		Annual Levels*		Per 10^{12} Btu Energy Produced	
		English Units	Metric Units		
	Air Pollutants				
③	Fugitive dust (coal preparation)	negligible		–	
⑥	Fugitive coal dust (unit train operation)	5.2×10^3 tons/yr	4.7×10^3 tonnes	0.43×10^3	
⑦	Fugitive coal dust (coal storage and handling)	not quantifiable		–	
⑳	Post-control flue gas constituents				
	• Sulfur dioxide (SO_2)	7.15×10^3 tons	6.49×10^3 tonnes	0.60×10^3 tons	0.42 lb/10^6 Btu
	• Oxides of nitrogen (NO_x)	10.2×10^3 tons	9.26×10^3 tonnes	0.85×10^3 tons	0.6 lb/10^6 Btu
	• Total suspended particulates (TSP)	0.525×10^3 tons	0.48×10^3 tonnes	0.04×10^3 tons	0.03 lb/10^6 Btu
	• Nonmethane hydrocarbons (HC)	0.32×10^3 tons	0.29×10^3 tonnes	0.03×10^3 tons	not established
	• Carbon monoxide (CO)	1.05×10^3 tons	0.95×10^3 tonnes	0.09×10^3 tons	↓
	• Carbon dioxide (CO_2)	3.7×10^6 tons	3.36×10^6 tonnes	0.31×10^6 tons	
	• Arsenic (As)	128 lb	58.1 kg	10.7 lb	
	• Beryllium (Be)	unknown	–	–	
	• Cadmium (Cd)	11.7 lb	5.3 kg	0.98 lb	
	• Manganese (Mn)	0.6 lb	0.27 kg	0.05 lb	
	• Lead (Pb)	32.1 lb	14.6 kg	2.68 lb	
	• Selenium (Se)	2.0 lb	0.9 kg	0.17 lb	
	• Uranium (U)	718 lb	325.7 kg	59.83 lb	
	• Zinc (Zn)	286 lb	129.7 kg	23.83 lb	
	• Radium-226 (Ra-226)	1.4×10^{-3} radioactive Ci/yr		0.12×10^{-3} Ci/yr	
	Water Pollutants				
⑤	Surface runoff, coal preparation, waste disposal site	not quantifiable			
⑧	Controlled runoff, plant coal storage site	not quantifiable			
⑩	Airborne water from cooling tower drift and evaporation	1.4×10^9 gal	5.3×10^9 liters	0.12×10^4 gal	
⑬	Evaporation from onsite water storage	28.5×10^6 gal	107.9×10^6 liters	2.38×10^6 gal	
⑯	Sluice water evaporated in boiler and retained in ash and	4.0×10^6 gal	15.1×10^6 liters	0.33×10^6 gal	
	Soot blowing and auxiliary steam and water	20.4×10^6 gal	77.2×10^6 liters	1.70×10^6 gal	
⑲	Water retained in sludge (water in recycle/reuse system)	2.5×10^6 gal	9.5×10^6 liters	0.21×10^6 gal	
⑭	Boiler blowdown to recycle	0.02×10^9 gal	0.08×10^9 liters		
⑪	Cooling tower blowdown to SO_2 scrubber	0.15×10^9 gal	0.57×10^9 liters		
⑮	General plant drains to ash sluice system	44×10^6 gal	166.5×10^6 liters		
	Solid Waste				
④	Solid wastes from coal preparation	20×10^3 tons	18.2×10^3 tonnes	1.7×10^3 tons	
⑰	Boiler bottom ash (dry)	34×10^3 tons	30.9×10^3 tonnes	2.83×10^3 tons	
⑱	Boiler fly ash (dry)	101×10^3 tons	91.7×10^3 tonnes	8.4×10^3 tons	
⑲	SO_2 scrubber sludge (dry)	43×10^3 tons	39.0×10^3 tonnes	3.58×10^3 tons	
㉒	Total solid waste to onsite disposal	177×10^3 tons	160.7×10^3 tonnes	14.75×10^3 tons	

*Based on the assumed 80% capacity factor.

OCCUPATIONAL SAFETY AND HEALTH

	Preparation Plant		Power Plant	
	Annual	Per 10^{12} Btu	Annual	Per 10^{12} Btu
Deaths	0.0033-0.0053	0.0003-0.0004	0-0.11	0-0.0095
Injuries	1.9-3.1	0.16-0.26	1.9-2.3	0.16-0.19

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II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

To identify current trends in western coal-fired power plant design, the features of 50 modern plants now under construction or recently brought online in six western states (Arizona, Wyoming, Utah, Colorado, Montana, and New Mexico) were examined.[1,2] On the basis of the observed trends, and through discussions with power engineers, a typical plant was chosen for characterization. This composite plant is a 500-MWe pulverized-coal plant burning western low-sulfur subbituminous coal with an electrostatic precipitator to control particulate emissions; a wet lime/limestone scrubber for flue gas desulfurization; and a wet, mechanical draft cooling tower. The plant was assumed to be supplied with coal by unit train deliveries from a thick seam surface mined coal with a minimum of preparation prior to pulverization.

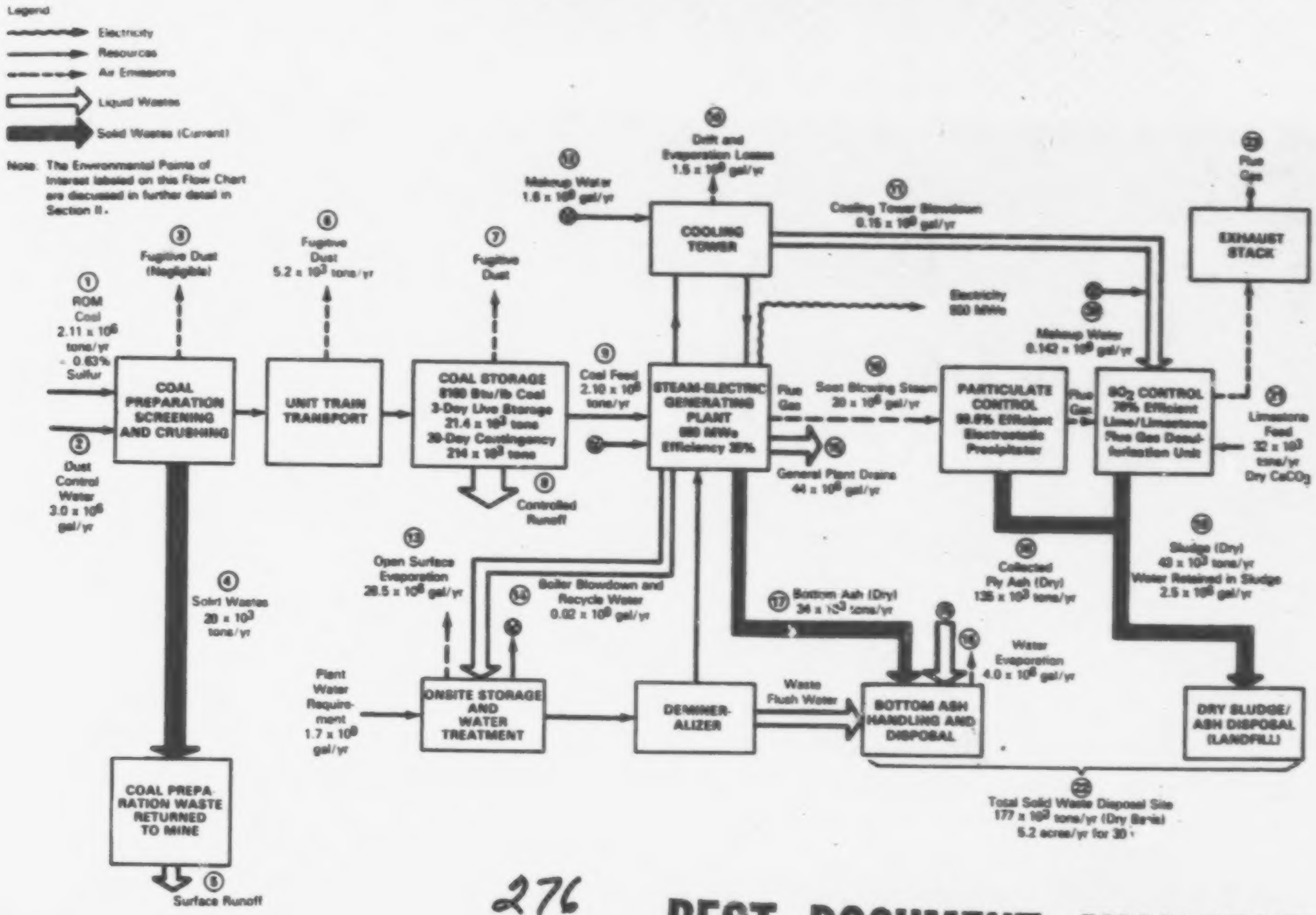
The net station heat rate of 9730 Btu/kWh corresponds to an overall efficiency of 35 percent. It was taken from an actual 500-MWe plant with similar controls and design features.[3] The coal used in the analysis is a western subbituminous coal with a heat value of 8100 Btu/lb, 0.63 percent sulfur, and 8.0 percent ash.[3,4]

The use of a western low-sulfur coal for electrical generation is shown in functional and flow form in Figure 1. Environmental points of interest have been identified in Figure 1 and are discussed in the following sections.

References

1. J.J. O'Connor, ed., Power, 1978 Plant Design Issue, Vol. 122, No. 11, November 1978.
2. Department of Energy "Inventory of Power Plants in the United States -- April 1979," DOE/EIA-0095, May 25, 1979.
3. Final Enviornmental Impact Statement, "Missouri Basin Power Project (Wheatland Generating Station Units 1, 2, and 3 and Associated Transmission, and Grayrocks Reservoir)," USDA-REA-EIS(ADM)76-2-F, May 1976.
4. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Wyoming, Powder River Coal, McGraw-Hill, New York, New York, 1978.

FIGURE 1.
PROCESS FLOW CHART WITH ENVIRONMENTAL POINTS OF INTEREST QUANTIFIED
– COAL-FIRED POWER PLANT –
(WESTERN LOW-SULFUR SUBBITUMINOUS COAL)
80% CAPACITY FACTOR


Legend
Electricity
Resources
Air Emissions
Liquid Wastes
Solid Wastes (Current)
Note: The Environmental Points of Interest labeled on this Flow Chart are discussed in further detail in Section II.
① ROM Coal 2.11 x 10^6 tons/yr - 0.63% Sulfur
② Dust Control Water 3.0 x 10^6 gal/yr
③ Fugitive Dust (Negligible)
④ Solid Wastes 20 x 10^3 tons/yr
⑤ Surface Runoff
⑥ Fugitive Dust 5.2 x 10^3 tons/yr
⑦ Fugitive Dust
⑧ Controlled Runoff
⑨ Coal Feed 2.10 x 10^6 tons/yr
COAL PREPARATION SCREENING AND CRUSHING
UNIT TRAIN TRANSPORT
COAL STORAGE 8100 Btu/lb Coal 3-Day Live Storage 21.4 x 10^3 tons 30-Day Contingency 214 x 10^3 tons
COAL PREPARATION WASTE RETURNED TO MINE
Makeup Water 1.6 x 10^9 gal/yr
Drift and Evaporation Losses 1.5 x 10^9 gal/yr
COOLING TOWER
Cooling Tower Blowdown 0.15 x 10^9 gal/yr
Electricity 800 MWe
STEAM-ELECTRIC GENERATING PLANT 880 MWe Efficiency 35%
Flue Gas
Soot Blowing Steam 20 x 10^6 gal/yr
General Plant Drains 44 x 10^6 gal/yr
PARTICULATE CONTROL 99.6% Efficient Electrostatic Precipitator
Flue Gas
Makeup Water 0.142 x 10^9 gal/yr
SO2 CONTROL 70% Efficient Lime/Limestone Flue Gas Desulfurization Unit
Limestone Feed 32 x 10^3 tons/yr Dry CaCO3
EXHAUST STACK
Flue Gas
Collected Fly Ash (Dry) 135 x 10^3 tons/yr
Sludge (Dry) 40 x 10^3 tons/yr Water Retained in Sludge 2.5 x 10^6 gal/yr
⑬ Open Surface Evaporation 28.5 x 10^6 gal/yr
⑭ Boiler Blowdown and Recycle Water 0.02 x 10^9 gal/yr
⑰ Bottom Ash (Dry) 34 x 10^3 tons/yr
Water Evaporation 4.0 x 10^6 gal/yr
Plant Water Requirement 1.7 x 10^9 gal/yr
ONSITE STORAGE AND WATER TREATMENT
DEMINERALIZER
Waste Flush Water
BOTTOM ASH HANDLING AND DISPOSAL
DRY SLUDGE/ ASH DISPOSAL (LANDFILL)
㉒ Total Solid Waste Disposal Site 177 x 10^3 tons/yr (Dry Basis) 5.2 acres/yr for 30 y

① Run-of-Mine Coal to Coal Preparation

The amount of run-of-mine (ROM) coal to the coal preparation plant is 2.11 x 10^6 tons/yr.

The ROM coal is assumed to be extracted from a western surface mine operating in thick seam subbituminous coal[1]. The mined material is assumed to contain very little refuse normally associated with underground mining. The material has moisture, most of which occurs naturally, but some of which may be added by sprays for dust control. The material is carried to the preparation plant by open-end haul trucks and to the power plant coal handling and storage area by unit trains. No Federal regulations apply to the characteristics of the mined material.

To determine the quantity of ROM coal entering the preparation plant, the net station heat rate, the proposed operating power level of the power plant, and the amount of material lost in preparation must be known. The typical power plant design used in this ECIR has a heat rate of 9730 Btu/kWh, and the generating plant operating level is 500 MWe. The preparation of this coal is confined to screening and crushing prior to shipment to the power plant site. It is assumed that 1 percent or less of the mined material is either rejected or lost during these operations.[2,3]

The calculations are as follows:

$$
\begin{aligned}
\text{Required (heat input)} &= \text{(Station power output)(net station heat rate)(hr/day)} \\
&= (5.0 \times 10^5\ \text{kWh/hr})(9730\ \text{Btu/kWh})(24\ \text{hr/day}) \\
&= 117 \times 10^9\ \text{Btu/day}
\end{aligned}
$$

Using the coal operation plant operating point of 1 percent rejection/loss, the cleaned coal will have an energy content of 8100 Btu/lb. Therefore,

ROM coal into the preparation screening and crushing plant =

$$
\begin{aligned}
&\frac{\text{(heat input)}}{\text{(coal heat content)(1 - rejection rate)}} \\
&= \frac{(117 \times 10^9\ \text{Btu/day})}{(8.1 \times 10^3\ \text{Btu/lb})\ (2 \times 10^3\ \text{lb/ton})(1 - 0.01)} \\
&= 7.2 \times 10^3\ \text{tons/day}
\end{aligned}
$$

On a yearly basis,

ROM coal into the preparation plant =

$$(7.2 \times 10^3 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$

$$= 2.11 \times 10^6 \text{ tons/yr}$$

The amount of ROM coal input for any preparation plant and power plant combination can be calculated for any coal by applying the known net station heat rate, the typical preparation plant rejection rate, and cleaned coal Btu content to the above formulas.

References

1. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, McGraw-Hill, New York, New York, 1978, pp. 602-608.
2. S.M. Cassidy, "Elements of Practical Coal Mining," Society of Mining Engineers, New York, New York, 1973, pp. 346-356.
3. P.J. Phillips and P.P. DeRienzo, "Assessing the Economics of Steam," Coal Preparation, Coal Mining and Processing, September 1977, p. 75.

② Coal Preparation Dust Control Water

The only water required for the preparation of typical thick seam western coals extracted from surface mines is for dust control. The water required for this function will typically be less than 3.0 x 10^6 gal/yr.

The coal preparation assumed in this system design consists only of screening and crushing operations. The use of water is confined to sprays for transfer, screening, and crushing operations.[1,2] Aside from these sprays, the coal is essentially dry except for the entrained moisture. The quality of water used in dust control is not critical, and it may come from any of a number of sources such as wells, streams, or mine dewatering.

Although the water requirement will generally vary directly with the preparation plant capacity, it is not necessarily directly scalable and will depend on empirical experience with a particular coal, the climatic conditions for the site, and the season of the year. The water required for this function in a mine having a production capacity of 10 x 10^3 tons per day will not typically exceed 3.0 x 10^6 gal/yr.[3]

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1. P.E. Polzin, "Water Use and Coal Development in Eastern Montana," Montana University Joint Water Resources Research Center, Bozeman, Montana, November 1974, pp. 5-13.
2. U.S. Geological Survey, "Landslides," INF 74-11, 1974.
3. "Coal Conversion Control Technology Vol I. Gaseous Emissions; Solid Wastes," EPA 600/7-79-228a, October 1979.

③ Fugitive Dust From Coal Preparation

Fugitive or stack particulate emissions from coal preparation are negligible (< 0.02 pound per ton) because no thermal drying or mine-site open coal storage is employed.[1]

Because the preparation facility functions are confined to screening and crushing of ROM and water sprays are used at the transfer points and at screening and crushing operations, there is little opportunity for fugitive dust emissions from the plant. Fugitive or stack particulate emissions from coal preparation are negligible (<0.02 pound per ton) because no thermal drying or mine-site open coal storage is employed.[1] Typical enclosed silo type coal storage, if used, would add little to these emissions. Exposed pile storage could be the source of windblown dust if no dust control measures such as compacting, water sprays, or surface coatings are used. There is a minimal requirement, however, for mine-site storage for mine-mouth power plant and unit-train delivery operations. A maximum of one trainload stored in loading silos would be typical.

If thermal drying of coal were used in this plant design, either to facilitate dry processing or for shipment preparation, dust emissions to the environment would occur. The uncontrolled emissions from three popular coal drying systems range from 15 to 25 lb of dust per ton of coal processed. The emissions to the atmosphere could be reduced to less than 0.075 lb per ton using cyclones followed by wet scrubbing.[1]

Reference

1. U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Third Edition, including supplements 1-7, PB 275-525, August 1977, pp. 346-347.

④ Solid Waste From Coal Preparation

The solid wastes rejected in coal preparation amount to 0.02 x 10^6 tons/yr.

Solid waste discharged from the preparation plant consists of shale and sandstone rejected in the cleaning process.[1,2] The exact composition of this material will vary widely from coal to coal as the loadings in the seam change and as site mining conditions and proximity to overburden change, but the coal content will be kept to a minimum.[2]

The calculation is as follows:

Coal preparation waste = (Rejection rate)(ROM coal feed rate)

For the typical plant,

$$\text{Coal preparation waste} = (0.01)(7.2 \times 10^3 \text{ tons/day}) = 72 \text{ tons/day}$$

On a yearly basis,

$$\text{Coal preparation waste} = (72 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 0.02 \times 10^6 \text{ tons/yr}$$

This material is transported with associated moisture back to the mine to be used as backfill. It will be compacted and rehabilitated through revegetation and stabilization techniques along with other mine backfill materials.[3] Water control must be installed for both surface and subsurface drainage of rehabilitated areas.

The amount of solid waste produced for a given coal and a given preparation plant scales linearly with changes in plant coal use. As more rock enters in the ROM coal, as in coal having major shale or rock partings, the refuse fraction can be expected to rise accordingly.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 47.
2. "West Shows Solid Growth," Coal Age, Mag 1980, pp. 93-100.
3. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15435-15439.

⑤ Surface Runoff From Coal Preparation Waste Disposal

Surface runoff for coal processing waste disposal sites is, in general, not quantifiable because it will be integral to the general mine excavation.

Runoff from surface coal mining areas will originate from two sources: rainfall on the surface of the fill and subsurface water. The requirement to cover with "topsoil" and revegetate and control drainage on the surface of the mined/disposal area will, in general, isolate the rainfall and surface water from the waste material.[1,2] Subsurface water, if present, can more readily come in contact with the waste material and this contact can result in the dissolving of solids (forming, for example, sulfates); the acidification of the liquids; or the deposition of suspended solids in the liquid. It is possible that a properly designed and operated drainage system will result in acceptable water quality for discharge to surface waters. If this quality cannot be achieved, treatment of the drainage from the area may be necessary to meet local regulations for dissolved solids, suspended solids, and acidity.[3]

As mining continues, the surface area of the backfilled area increases, and there will be a general increase in the opportunity for ingress of surface (rain) water and for intrusions of subsurface water. Neither of these sources of surface water can be accurately or generically quantified because they will depend on the actual rainfall and hydraulic conditions at a particular site.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 48.
2. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15434-15436 and 15424-15430.
3. Personal Communication, Garry Beech, Wyoming Department of Environmental Quality, Land Division, May 28, 1980.

⑥ Unit Train Coal Transport

The 0.72 unit train/day needed to supply coal to the plant can cause 5.2 x 10^3 tons/yr of fugitive dust emissions from the moving cars and be responsible for accidents resulting in 0.28 death/yr and 1.9 injuries/yr in the public and job-related sectors from increased rail traffic. Noise levels may substantially affect people living within 1 mi of the rail line.

A 10,000-ton-per-trip unit train operating on a 0.72 trip/day schedule can supply the 7.2 x 10^3 tons of coal per day required for operation of the power plant.

Unit trains are the predominate mode for the movement of western coal to non-mine-mouth power plants.[1] Such trains made up of 80 to 120 or more 100-ton-per-car open hopper cars travel on a fixed route from the mine to the power plant coal handling facility.

One of the prime environmental impacts of such a unit train operation will be the loss of coal fines from the top of the open cars. This loss is exacerbated somewhat in western soft coals (e.g., subbituminous and lignite as opposed to eastern bituminous) due to their low mechanical strength causing crumbling, particularly during handling or in transport. Fines on top of the loaded car are easily blown off due to natural and motion-induced wind erosion. The coal loss through fugitive dust emissions (windage) is estimated as 0.25 percent of the total coal transported.[2] Using this efficiency, the fugitive dust is given by

$$\begin{aligned}\text{Fugitive dust} &= 0.0025\ (\text{total coal transported/yr})\\ &= 0.0025\ (2.1 \times 10^6\ \text{tons/yr})\\ &= 5.2 \times 10^3\ \text{tons/yr}\end{aligned}$$

Some control of these emissions can be achieved by spraying the top surface of the load with a surface binder such as tar, black liquor, or latex; however, even these may lose much of their effectivneess on longer trips. Fugitive dust emissions can also be controlled through the use of closed or covered hopper cars, but the physical and chemical properties of some coals raise the potential problem of spontaneous combustion during shipment.

Although unit-train operation does not exhibit any unique concerns for public and worker safety with respect to operation-related deaths and injuries, a general increase in train traffic on a particular route resulting from such operations will increase exposure to the possibility of accident. Although trains operating in the West may be expected to expose fewer people due to the decreased population density, grade crossings and operation through or near populated areas will expose the general public to the hazards of accidents. The occupational exposure to accidents should be similar from East to West.

The impact of noise will be most severe where the rail line travels within 1 mile or less of residential or light business areas. In such instances, noise levels can be expected to exceed 56 decibels. Much of the travel within western states may be expected to be away from populated areas, but it has been estimated in one environmental assessment that more than 1 million people live within 1 mile or less of the main Montana-to-Chicago railroad.[3] People living in such proximity are considered to be heavily impacted by noise exposure.

References

1. Mitre Corp., "Resource and Land Investigations (RALI) Program: An Approach to Environmental Assessment With Application to Western Coal Development," August 1975, p. IV-11.
2. U.S. Department of Energy, "Environmental Data, Energy Technology Characterizations, Coal," DOE/EV-0061/3, Vol. 3, January 1980.
3. "Energy From the West," EPA-600/7-79-082a, Office of Energy, Minerals, and Industry, Washington, D.C., March 1979.

⑦ Fugitive Dust From Onsite Coal Storage

It is not possible to accurately quantify the fugitive dust emissions from the coal storage area. Wind erosion resulting in airborne dust should not be a significant air pollution source for active piles if dust control measures are maintained.

Coal fines are an inevitable[1,2] result of coal preparation and handling operations. Dust emissions from the storage areas, especially active storage, can be effectively controlled through the use of surface compaction and, if necessary, water sprays. In addition, oil, asphalt, or latex coatings can be applied to long-term storage piles to control dust emissions. It should also be noted that the surface of a properly compacted long-term storage pile will quickly lose the fines, which can become airborne through trickle stratification or wind erosion, and the dust emissions will drop to a relatively low level unless the pile is physically disturbed.

The dust emissions from an open coal storage pile are not, in general, quantifiable. They are, however, proportional to the exposed surface of the coal pile and generally will increase with increases in surface wind velocity.[2]

References

1. T.H. Pigford et al., "Fuel Cycles for Electrical Power Generation," EEED-101 Teknekron, Inc., Berkeley, California, January 1973.
2. U.S. Environmental Protection Agency, "Survey of Fugitive Dust From Coal Mines," EPA-908/1-78-003, February 1978, pp. 2 and 56.

⑧ Controlled Runoff From Onsite Coal Storage

It is not possible to quantify the liquid runoff from the coal storage areas because the source of this liquid is primarily rainfall and, to a much lesser extent, any water sprays that may be used to control dust in working storage areas.[1]

Subsurface water is excluded from the coal storage area by natural earth formations such as clay or an impermeable membrane liner. Water that falls on the surface of the coal pile will either be lost to the air through evaporation or be drained to a peripheral drainage channel where it can be routed to the power plant water treatment system. This water may contain suspended solids and dissolved solids; be slightly acidic; and contain oil, if oil sprays are used in dust control. The receiving water treatment system is designed to handle such pollutants through settling, neutralization, oil removal, and blending to achieve acceptable water quality for recycling uses in the system.

The quantity of runoff is proportional to the surface area of the coal storage pile, the rate of precipitation at the site, and the imperviousness of the impingement area.

Reference

1. U.S. Environmental Protection Agency, "Environmental Assessments of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, pp. 44 and 45.

⑨ Coal Feed to Generating Plant

The amount of prepared coal required for a typical 500-MWe power plant operating at 80% annual capacity is 2.10×10^6 tons/yr.

To determine how much coal is required to run any given power plant, the following information is needed:

- Net power delivered to the transmission grid (P) in MWe
- Net station heat rate ($\dot{Q}$) in Btu/kWh
- Heat content of coal, as fired (Q) in Btu/lb

The power delivered to the grid is known for a given plant (i.e., the nominal rating of 500 MWe, 1000 MWe, etc.)

The net station heat rate ($\dot{Q}$), which varies from plant to plant, is a measure of the amount of heat (Btu) that must be fed into the boiler to get 1 kWh of electricity out to the grid. Net power delivered to the grid equals total power generated minus power required to operate plant auxiliaries, including environmental control equipment. The actual overall plant heat rate is listed in the plant's planning and design documents, such as the Environmental Impact Statement or the Power Plant Design Report.

The heat content of coal (Q) as fired is given in the coal analysis.

Using the above definitons, the coal required on a daily basis is as follows:

$$\frac{(P)(\dot{Q})}{Q}\left[\left(\frac{1 \times 10^3 \text{ kWe}}{\text{MWe}}\right)\left(\frac{1 \text{ ton}}{2 \times 10^3 \text{ lb}}\right)\left(24 \text{ hr/day}\right)\right] = 12\, P\dot{Q}/Q \text{ tons/day}$$

In the typical plant,

$P = 500$ MWe
$\dot{Q} = 9730$ Btu/kWh
$Q = 8100$ Btu/lb

Thus, for the typical plant,

$$\text{Coal feed rate} = 12\, P\dot{Q}/Q \text{ tons/day}$$

$$\text{Coal feed rate} = \frac{12\ (500 \text{ MWe})(9730 \text{ Btu/kWh})}{8100 \text{ Btu/lb}}$$

$$= 7.2 \times 10^3 \text{ tons/day}$$

On a yearly basis,

$$\begin{aligned}\text{Coal feed rate} &= (7.2 \times 10^3 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 2.10 \times 10^6 \text{ tons/yr}\end{aligned}$$

The analysis for a typical western low-sulfur coal is as follows[1]:

Proximate Analysis (%)	
ash	8.0
fixed C	36.0
volatile material	27.5
moisture	27.5
sulfur	0.63

Ultimate Analysis (%)	
C	68.23
O	17.14
H	5.04
N	0.96
S	0.63
ash	8.0

Heat value -- 8100 Btu/lb

In subsequent sections of this ECIR, values from this coal analysis are used to calculate the resources and residuals associated with operation of the plant, e.g., in item ⑰ , Bottom Ash From Coal Combustion, the ash content of the coal is used to calculate the amount of bottom ash from combustion. If a coal different from the one shown in the above table were used, the values from the new coal analysis would be substituted in the equations.

In the calculations of environmental pollutants, it is assumed that 20 percent of the ash is emitted as bottom ash and that the remaining 80 percent is emitted from the boiler as fly ash.[2,3] It is also assumed that 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and the remaining 90 percent is converted to sulfur dioxide.[4,5]

The energy content of the coal feed into the boilers is converted into electricity with an efficiency of 35 percent. The remainder of the energy is lost in the form of thermal energy as shown in Table 2.[6]

These heat losses pose little environmental concern: the heat rejected directly to the atmosphere is negligible, the heat rejected to the main condenser is cooled by closed-cycle cooling towers, and heat rejected through the cooling tower blowdown line is dissipated into the atmosphere through water treatment/recycling facility holding ponds.

Table 2. Energy Lost as Thermal Energy

	Percent of Input	Energy at 100-Percent Capacity (Btu/day)
Net Electrical Output	35	41×10^9
Heat Rejected to Condenser	50	58.5×10^9
Sensible Heat in Flue Gas	10.7	12.5×10^9
Internal Thermal Losses and Plant Consumption	4.3	5×10^9
Total Energy From 7.2×10^3 tons/day Coal Feed at 8100 Btu/lb	100	117×10^9

References

1. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Wyoming Powder River Coal, McGraw-Hill, New York, New York, 1978.
2. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
3. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
4. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C, April 1980.
5. Personal Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality, Planning, and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
6. Teknekron, Inc., "Towards Comprehensive Standards: The Electric Power Case," EPA No. 68-01-0561, January 1973, p. 70.

⑩ Evaporative and Drift Losses From the Wet Cooling Towers

Evaporative losses from the cooling towers into the atmosphere are approximately 1.4 x 10^9 gal/yr for a typical 500-MWe power plant operating at full load. Additionally, another 0.25 percent or 3.6 x 10^6 gal/yr will be lost in the form of drift if drift eliminators are not used.

Evaporation is the loss of water from the circulating cooling water circuit through conversion to water vapor by the rejected heat. Drift loss is the physical entrainment of a portion of the circulating cooling water in the form of small water droplets. Together, evaporation and drift losses account for the major consumptive use of water in western power plants using wet cooling towers.

The above values for this loss are based on the assumptions that 50 percent of the gross heat released from coal combustion is dissipated to the circulating water system and that the water heat of vaporization and loss through convection at conditions found in the Great Plains area is 1430 Btu/lb water evaporated.[1,2,3] In general, the water requirements due to cooling tower evaporation are given by

$$W_{EVAP}\text{, gal/day} = 2880\ (\text{percent heat rejected to circulating water system})\ \dot{Q}P/(\text{water heat of vaporization})$$

For the typical plant,

$$\begin{aligned} W_{EVAP} &= (2880)(0.50)(9730\ \text{Btu/kWh})(500\ \text{MWe})/(1430\ \text{Btu/lb}) \\ &= 4.9 \times 10^6\ \text{gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{EVAP} &= (4.9 \times 10^6\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 1.4 \times 10^9\ \text{gal/yr} \end{aligned}$$

Similarly, requirements due to cooling tower drift for the typical plant are

$$\begin{aligned} W_{DRIFT} &= 0.0025\ W_{EVAP} \\ &= 0.0025\ (4.9 \times 10^6\ \text{gal/day}) \\ &= 12.3 \times 10^3\ \text{gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{DRIFT} &= (12.3 \times 10^3\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 3.6 \times 10^6\ \text{gal/yr} \end{aligned}$$

These cooling tower emissions may condense under ambient conditions and cause visibility impairment, fogging, or icing conditions. There are no existing regulations limiting cooling tower losses to the atmosphere.

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 61-105.
3. Power Handbook: Basic Power Facts Made Easy, Part One and Part Two, Power Magazine, 1975, p. 104.

⑪ Cooling Tower Blowdown

Cooling tower blowdown represents approximately 10 percent of the evaporation losses.[1,2] *For a typical plant, blowdown is* 0.15×10^9 *gal/yr. This water is used as part of the makeup water in the* SO_2 *scrubber.*

Blowdown water, the water regularly withdrawn as waste from the recirculating cooling water system to control the buildup of solid and liquid contaminants in the system, typically contain the following environmental residuals: biocides (e.g., chlorine), added for marine and biological growth control, and corrosion inhibitors (e.g., chromates), a high concentration of total dissolved solids. These residuals are collected and controlled in the water treatment/recycling facility, and there is no direct influence on the environment.

For any plant,

$$W_{BLOWDOWN} = 0.1\ W_{EVAP}$$

For the typical plant,

$$W_{BLOWDOWN} = 0.1\ (4.9 \times 10^6 \text{ gal/day})$$
$$W_{BLOWDOWN} \approx 0.5 \times 10^6 \text{ gal/day}$$

On a yearly basis,

$$\begin{aligned} W_{BLOWDOWN} &= (0.5 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.15 \times 10^9 \text{ gal/yr} \end{aligned}$$

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, p. 47.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 69.

⑫ Cooling Tower Makeup

Approximately 1.6 x 10^9 gal/yr are needed to make up cooling tower losses due to drift, evaporation, and blowdown for a typical plant.

Cooling tower makeup water must be of sufficient quality to avoid fouling the heat transfer surfaces and piping in the cooling tower system. In typical eastern plant designs, this is accomplished through the use of fresh water with the addition of appropriate biological growth control agents such as chlorine. In western plant design where greater water conservation is typically practiced, cooling tower makeup must still be treated but the supply from which it is taken may be partially composed of recycled water from such sources as boiler blowdown wastes. Cooling tower makeup is obtained by summing W_{EVAP} and W_{DRIFT} from item ⑩, Evaporative and Drift Losses From the Wet Cooling Towers, and $W_{BLOWDOWN}$ from item ⑪, Cooling Tower Blowdown, as follows:

$$W_{TOW} = W_{EVAP} + W_{DRIFT} + W_{BLOWDOWN}$$

For the typical plant,

$$\begin{aligned} W_{TOW} &= (4.9 \times 10^6 \text{ gal/day}) + (0.0123 \times 10^6 \text{ gal/day}) + (0.5 \times 10^6 \text{ gal/day}) \\ &= 5.4 \times 10^6 \text{ gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{TOW} &= (5.4 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 1.6 \times 10^9 \text{ gal/yr} \end{aligned}$$

The above analysis is for a wet cooling system only. When water is expensive, however, (greater than about \$0.80/10^3 gal) or of limited availability, combined wet and dry cooling systems could be used. For such systems, the average annual water consumption is between 10 and 25 percent of the all wet system.[1]

Reference

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.

⑬ Onsite Water Storage

Evaporative water loss from onsite raw water storage totals approximately 28.5 x 10^6 gal/yr.

Because of the uncertain characteristics of water availability throughout many parts of the West, it is normal practice to include an onsite raw water storage facility to act as an emergency supply should the normal supply be inadequate. Although the size of this storage facility will be determined by the plant capacity, there is no direct relationship between plant capacity and surface area except that a 10 to 20 day supply for the plant is normally considered to be the required total capacity. Desirable design criteria include the reduction of the surface area, thereby reducing raw water loss through evaporation. Deeper ponds will also allow the thermal stratification of the water and the selective withdrawal of cooler waters for cooling purposes. In the case of the base plant design, this is assumed to be a pond having a surface area of 25 acres and a depth of 10 feet.[1,2] The open surface evaporation can be calculated as follows:

$$W_{SEV}\ \text{gal/yr} = \frac{(\text{average net evaporation rate-in./yr})(\text{surface area-acres})(3.26 \times 10^5\ \text{gal/acre-ft})}{12\ \text{in./ft}}$$

$$= \left(\frac{42\ \text{in./yr (Ref. 3)}}{12}\right)\left(25\ \text{acres}\right)\left(3.26 \times 10^5\ \text{gal/acre-ft}\right)$$

$$= 28.5 \times 10^6\ \text{gal/yr}$$

There are no Federal regulations regarding the construction and operation of such water storage facilities.

References

1. Basin Electric Power Cooperative, "Final Environmental Impact Statement, Missouri Basin Power Project (Wheatland Generating Station)," Bismarck, North Dakota, May 1976, pp. 13-15.
2. Burns and McDonnel, "Application for Permit to Wyoming Industrial Siting Council for Construction of the Laramie River Station," Kansas City, Missouri, 1975, Exhibits 3, 4, 5, and 6.
3. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1970, pp. 252 and 256.

⑭ Recycled Water and Plant Discharges

The amount of water recycled within the plant is 0.196×10^9 gal/yr under the zero discharge design philosophy.

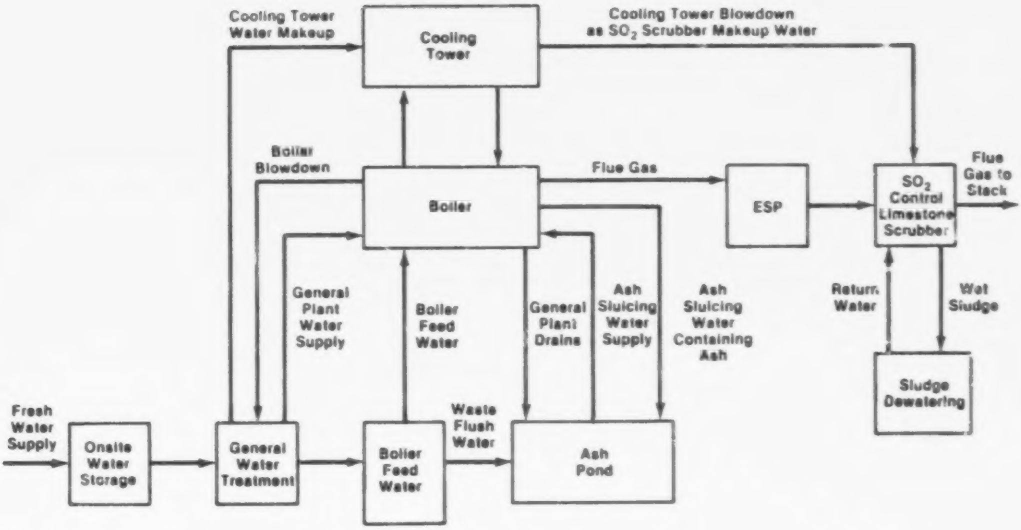
Water throughout the West is considered a very valuable, and in many locations scarce, quantity. Therefore, the typical design of power plants for this area stresses minimal consumptive usage of water.[1] This objective requires the overall plant water supply to be arranged in a cascade such that the stream containing waste water of one process or function becomes the water source for some other function or process. For example, in this design (Figure 2), cooling tower blowdown (waste) is used as makeup water for the SO_2 scrubber, and boiler blowdown is recycled to the raw water storage area where it can be reused.[2]

In such designs, zero discharge is not uncommon. This means that no liquid waste streams will be discharged to the environment. Water treatment of waste streams to facilitate their general reuse or use of the waste stream of one function as a makeup water source for another function (e.g., cooling tower blowdown as part of the feedwater for the SO_2 scrubber unit) are integral to a zero discharge system. By recycling waste streams such as general plant drains (including bearing cooling water, demineralizer flush water, and service water), and waste water from water treatment facilities, a substantial amount of water is saved or reused. The dry disposal of scrubber sludge further reduces the water requirement of the plant by eliminating the loss of most of the water normally entrained in wet sludge disposal methods (10 to 40 percent of the dry sludge weight).

In addition, water requirements can be further reduced by application of less consumptive processes (a step not fully exploited in this design) such as dry cooling (75- to 90-percent reduction), dry or semi-dry SO_2 scrubbing (50-percent reduction),[3] and dry ash conveying systems (60- to 80-percent reduction).

The use of a zero discharge design philosophy will generally result in the concentration of water contaminants in a dry form through either evaporation ponds or water treatment waste sludges. Although these wastes are generally small in volume, they must be disposed of in such a way (dry lined and fill on site in the case of the base plant) so as not to contaminate surface water or groundwater at the ultimate disposal site. Suitable dry disposal sites will in general be easier to establish and maintain in the West because of both climate and soil conditions.

FIGURE 2
RECYCLE WATER FLOW


Cooling Tower Water Makeup
Cooling Tower
Cooling Tower Blowdown as SO_2 Scrubber Makeup Water
Boiler Blowdown
Boiler
Flue Gas
ESP
SO_2 Control Limestone Scrubber
Flue Gas to Stack
General Plant Water Supply
Boiler Feed Water
General Plant Drains
Ash Sluicing Water Supply
Ash Sluicing Water Containing Ash
Return Water
Wet Sludge
Sludge Dewatering
Fresh Water Supply
Onsite Water Storage
General Water Treatment
Boiler Feed Water
Waste Flush Water
Ash Pond

The amount of water recycled or saved can be calculated as follows:

Recycled water gal/day = (boiler blowdown gal/day) + (cooling tower blowdown gal/day) + (plant wastewater) + (water treatment wastewater)

$$W_{RCY}\ \text{gal/day} = W_{BBD} + W_{CBD} + W_{PWW} + W_{WTW}$$

For the typical plant,

$$W_{RCY} = 0.07 \times 10^6\ \text{gal/day (Ref. 2)} + 0.50 \times 10^6\ \text{gal/day (Item ⑪)} + 0.03 \times 10^6\ \text{gal/day} + 0.07 \times 10^6\ \text{gal/day}$$

$$= 0.67 \times 10^6\ \text{gal/day}$$

On a yearly basis

$$\boxed{\begin{aligned} W_{RCY} &= (0.67 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.196 \times 10^9 \text{ gal/yr} \end{aligned}}$$

Varying designs and plant geographical locations will affect the exact amount of water available for recycle. Exact figures for other plant designs must be obtained from the specific plant flowsheets. In general, the water available from boiler and cooling tower blowdown streams will increase as the plant increases in capacity. Water from plant drains and water treatment facilities will increase but not directly as plant capacity increases.

Although there are no Federal regulations requiring the reuse of water, siting permits issued by various states will depend on the demonstrated adequacy of the available water supply for the particular project. Water conservation practices such as recycling can make a major contribution to this goal.

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
2. Basin Electric Power Cooperative "Final Environmental Impact Statement, Missouri Basin Power Project (Wheatland Generating Station)," Bismarck, North Dakota, May 1976, p. 13.
3. K.E. Janssen and R.L. Erikesn, "Basin Electric's Involvement With Dry Flue Gas Desulfurization," EPA Symposium on Flue Gas Desulfurization, Las Vegas, Nevada, March 1974, p. 4.

⑮ Miscellaneous Plant Drains

The typical liquid waste flow from miscellaneous plant drains is estimated to be 44 x 10^6 gal/yr, all of which is recycled in the facility.[1]

The liquid waste consists of various water streams used in maintaining plant operation (e.g., boiler blowdown, demineralizer waste, bearing cooling, and sanitary treatment liquid wastes) and can be slightly contaminated with oil or chemicals. The typical liquid waste flow from miscellaneous plant drains is estimated to be 44 x 10^6 gal/yr, all of which is recycled in the facility.[1]

In a zero discharge design, these streams will either be directly recycled to appropriate uses, treated for recycle, or placed in evaporative disposal ponds. In general, the volume of these streams will increase with plant size. However, because the magnitude of the waste stream is not a linear function of plant power level, the waste from a power plant of a size other than 500 MWe should be obtained from an actual plant of that size. Such information is contained in the plant's Environmental Impact Statement.

Reference

1. Final Environmental Impact Statement, "Wheatland Generating Station, Units 1, 2, and 3," U.S. Department of Agriculture, USDA-REA-EIS(ADM)76-2-F, May 1976, p. 13.

⑯ Water Consumption of Generating Plant

The makeup water to the generating plant is 24×10^6 gal/yr. r.

Because of the restrictions on the availability of water in most western areas, plant design generally stresses water conservation through efficient usage and the maximum use of recycled water. The design of the basic plant examined in this document uses a zero discharge water system. That is, no water is discharged to the environment as a waste stream. All consumptive usage of water is accounted for in evaporative usage or loss or entrapment in either the bottom ash or the SO_x scrubber sludge. This operating condition is achieved through the recycle of some of the more significant liquid waste streams common in plants not operating under zero discharge designs. These recycle streams are discussed in item ⑭, Recycled Water and Plant Discharges.

Consumptive water use directly associated with operation of the boiler in this system are water loss in the bottom ash sluicing system and ash disposal pond and boiler water lost in the form of steam used for soot blowing and other non-recoverable uses.

Bottom ash is collected and quenched in water-filled hoppers before it is sluiced to a disposal site. The rate at which water is evaporated from the hopper, W_{VAP}, is a function of the ash specific heat, temperature drop, quenching rate, and water heat of vaporization, i.e.,[1]

$$W_{VAP}, \text{ gal/day} = 240 \text{ (ash fraction in coal)(coal feed rate)(bottom ash fraction)} \\ \text{(bottom ash temperature change)(bottom ash specific heat)/} \\ \text{(water heat of vaporization)}$$

For the typical plant, if it is assumed that

Ash removal temperature = 1200° F
Ash quenched temperature = 200° F
Ash specific heat = 0.2 Btu/lb-° F
Water heat of vaporization = 1.050×10^3 Btu/lb
Bottom ash fraction = 0.2

then

$$W_{VAP} = 240\ (0.08)(7.2 \times 10^3 \text{ tons/day})(0.2)(1000^\circ\text{F})(0.2 \text{ Btu/lb-}^\circ\text{F})/(1050 \text{ Btu/lb}) \\ = 5.3 \times 10^3 \text{ gal/day}$$

On a yearly basis,

$$W_{VAP} = (5.3 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 1.54 \times 10^6 \text{ gal/yr}$$

Of equal importance to the water evaporated is the amount of excess water needed for bottom ash handling and disposal, W_{HAD}. If the weight of water remaining in the quenched ash is 30 percent of the ash weight, then

$$W_{HAD,\ gal/day} = 72 \text{ (ash fraction in coal)(coal feed rate)(bottom ash fraction)}$$

For the typical plant,

$$W_{HAD} = 72\ (0.08)(7.2 \times 10^3 \text{ tons/day})(0.2)$$
$$= 8.30 \times 10^3 \text{ gal/day}$$

On a yearly basis,

$$W_{HAD} = (8.3 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 2.42 \times 10^6 \text{ gal/yr}$$

The total water requirement for bottom ash disposal, W_{BA}, is therefor given as

$$W_{BA} = W_{VAP} + W_{HAD}$$

For the typical plant

$$W_{BA} = (13.6 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 4.00 \times 10^6 \text{ gal/yr}$$

The use of steam for the removal of soot deposits inside the boiler represents a significant consumptive use of steam/water. While this usage is difficult to quantify because of varying operating procedures and soot accumulation conditions, the value presented here is for an actual 500-MWe plant and is typical of usage in plants of similar design and operating conditions (i.e., low-sulfur pulverized coal).[2] Steam may also be used for other cleaning, heating, or motive functions in which the associated water is lost. These will be much smaller (< 10 percent) than the amount of steam used for soot blowing:

$$\boxed{\begin{aligned} W_{SB} &= \text{Total water consumed as steam for soot blowing and in plant use} \\ &= 70 \times 10^3 \text{ gal/day} \end{aligned}}$$

On a yearly basis,

$$\boxed{\begin{aligned} W_{SB} &= (70 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 20 \times 10^6 \text{ gal/yr} \end{aligned}}$$

The total water consumed by the boiler, W_{BT}, for bottom ash handling and soot blowing is therefore given on a yearly basis as

$$\boxed{W_{BT} = W_{BA} + W_{SB}}$$

For the typical plant,

$$\boxed{\begin{aligned} W_{BT} &= 4 \times 10^6 \text{ gal/yr} + 20 \times 10^6 \text{ gal/yr} \\ &= 24 \times 10^6 \text{ gal/yr} \end{aligned}}$$

References

1. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, Chapter 8, August 24, 1976, p. 141.
2. Basin Electric Power Cooperative, "Final Environmental Impact Statement, Missouri Basin Power Project (Wheatland Generating Station)," Bismarck, North Dakota, May 1976, p. 13A.

⑰ Bottom Ash From Coal Combustion

The amount of bottom ash generated is 34 x 10^3 tons/yr.

As described earlier, the quantity of ash in the coal assumed for this ECIR is 8.0 percent, and 20 percent of this ash becomes bottom ash.[1,2] Thus,

$$\text{Bottom ash} = (\text{ash fraction in coal})(\text{coal feed rate})(\text{bottom ash fraction})$$

For the typical plant

$$\begin{aligned}\text{Bottom ash} &= (0.08)(7.2 \times 10^3 \text{ tons/day})(0.20)\\ &= 115 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Bottom ash} &= (115 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})\\ &= 34 \times 10^3 \text{ tons/yr}\end{aligned}$$

Bottom ash from a dry bottom pulverized coal boiler is collected and quenched in hoppers, located beneath the boiler, where it is sluiced with water to settling ponds or dewatering bins.[3]

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plant in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 142.

(18) Fly Ash From Particulate Control

The total amount of fly ash generated is 135 x 10^3 tons/yr. Approximately 75% or 101 x 10^3 tons/yr are disposed of onsite, and 25% or 34 x 10^3 tons/yr are disposed of as a valuable byproduct.

Dry electrostatic precipitators are used to remove the coal fly ash from the flue gas. Eighty percent of the ash in the coal is emitted as fly ash,[1,2] or

$$\text{Fly ash} = (\text{ash fraction in coal})(\text{coal feed rate})(\text{fly ash fraction})$$

For the typical plant,

$$\begin{aligned}\text{Fly ash} &= (0.08)(7.2 \times 10^3 \text{ tons/day})(0.80)\\ &= 461 \text{ tons/day}\end{aligned}$$

On an annual basis,

$$\begin{aligned}\text{Fly ash} &= (461 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})\\ &= 135 \times 10^3 \text{ tons/yr}\\ &= 101 \times 10^3 \text{ tons/yr (or 75\%) for disposal and } 34 \times 10^3 \text{ tons/yr (or 25\%)}\\ &\quad \text{as a salable byproduct}\end{aligned}$$

Less than 0.4 percent of this amount will be emitted to the ambient atmosphere because approximately 99.6 percent will be captured by the electrostatic precipitator, and 5 to 30 percent of the remainder will be captured in the SO_2 scrubbing system.

From these precipitators, the collected ash is discharged into storage hoppers by rapping. The dry fly ash is transported by pneumatic conveying from the precipitator to the storage hoppers or to the SO_2 scrubber sludge disposal facility where it will be used in the sludge fixing process as a drying agent and filler. Approximately 25 percent (110 tons/day) are disposed of as a salable byproduct for construction materials.

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.

⑲ Sludge From SO_2 Control

The amount of scrubber sludge generated (on a dry basis) is 43 x 10^3 tons/yr.

The quantity of sulfur in the coal used is 0.63 percent. Therefore, the quantity of sulfur entering the boiler is

$$\begin{aligned} S &= \text{(sulfur fraction in coal)(coal feed rate)} \\ &= 0.0063\ (7.2 \times 10^3\ \text{tons/day}) \\ &= 45\ \text{tons/day} \end{aligned}$$

If it is assumed that a total of 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and that the remainder of the sulfur is converted to SO_2, then

$$\begin{aligned} SO_2 &= 0.9\ \text{(sulfur entering boiler)}\ (2) \\ &= 0.9\ (45\ \text{tons/day})(2) \\ &= 81\ \text{tons/day} \end{aligned}$$

Thus, 81 tons/day of SO_2 enter the scrubber.[1-4] (Note: The factor "2" in this equation is used because every mole of sulfur requires 1 mole of oxygen to form 1 mole of SO_2.) As will be shown in item ㉑, Lime/Limestone Requirement for SO_2 Control, the amount of dry limestone used is 110 tons/day, i.e., 1.25 times the stoichiometric requirement. This excess 25 percent of the stoichiometric requirement will become part of the sludge residue. It is generally accepted[5] that the spent slurry consists of 75 percent $CaSO_3 \cdot \frac{1}{2}H_2O$ and 25 percent $CaSO_4 \cdot 2H_2O$. As will be shown in item ㉓, Flue Gas, the scrubber must operate at 70 percent efficiency to meet the standard. Consequently, the amount of scrubber sludge (dry basis) generated each day is

$$\begin{aligned} \text{Sludge} &= [0.25\ (100/64) + (140/64)]\ \text{(scrubber efficiency)}(SO_2\ \text{feed rate)} \\ &= [0.25\ (100/64) + (140/64)]\ (0.70)(81\ \text{tons/day}) \\ &= 146\ \text{tons/day} \end{aligned}$$

On a yearly basis,

$$\text{Sludge} = (146 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 43 \times 10^3 \text{ tons/yr}$$

where

100/64 = limestone/SO_2 molecular weight ratio
140/64 = ($CaSO_3 \cdot \frac{1}{2}H_2O$ and $CaSO_4 \cdot 2H_2O$) mixture/SO_2 molecular weight ratio

Under previous Federal New Source Performance Standards limiting sulfur dioxide emissions to 1.2 lb/million Btu, no specific percentage of sulfur dioxide reduction over uncontrolled emissions for a particular coal was required (Appendix A). Under this regulation, low-sulfur coal having a sulfur content such that less than 1.2 lb/million Btu would be emitted to the atmosphere was an acceptable control approach. Low-sulfur coal in combination with other techniques such as coal cleaning and sulfur dioxide scrubbing were also acceptable approaches. Under these regulations, low-sulfur coal was sometimes referred to as "compliance coal" because it could meet or contribute to meeting applicable standards. Such coal is still in use in power plants that due to their date of construction are subject to the previous Federal New Source Performance Standards regulations. New regulations, as explained in item ㉓, Flue Gas, require a specific percentage of sulfur removal (which is not less than 70 percent for any coal) from the specific coal used.

References

1. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C.
2. Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
3. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA-450/2-78-007a, July 1978.
4. U.S. Environmental Protection Agency, "Position Paper on Regulation of Atmospheric Sulfates," EPA-450/2-75-007, September 1975.
5. Aerospace Corporation, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-0446, March 1978.

⑳ Makeup Water for SO_2 Control

The amount of makeup water required for flue gas desulfurization is 142 x 10^6 gal/yr.

For this analysis, a lime/limestone slurry is used in the scrubber, and it is assumed that the flue gas is saturated with water vapor upon leaving the scrubber. Typical conditions at this location are $P = 15.056$ psia and $T = 102^\circ F$, which correspond to flue gas containing 0.127 mole water/mole dry gas. If the fractional weights of carbon (C), sulfur (S), hydrogen (H), oxygen (X), and water (W) in the coal are known, and 15 percent excess air is assumed, it can be shown that the makeup water requirement per unit weight of coal is given by the following relation:[1,2]

$$\frac{\text{lb makeup water}}{\text{lb coal}} = 12.8\left(\frac{C}{12} + \frac{S}{32}\right) + 10.5\left(\frac{H}{4} - \frac{X}{32}\right) - W - \frac{H}{9}$$

Using the coal feed rate obtained previously, the above equation can be modified to give the required daily water feed rate, W^1_{FGD}:

$$W^1_{FGD}, \text{ gal/day} = \left|12.8\left(\frac{C}{12} + \frac{S}{32}\right) + 10.5\left(\frac{H}{4} - \frac{X}{32}\right) - W - \frac{H}{9}\right|\left(2.88 \times 10^3 \frac{P\dot{Q}}{Q}\right)$$

In addition to water vapor leaving with the flue gas, there is also going to be some water leaving with the solid wastes, e.g., $CaSO_3 \cdot \frac{1}{2}H_2O$ and $CaSO_4 . 2H_2O$. It is to be noted that, for the purposes of these calculations, the amount of water of hydration is considered negligible. The amount of water leaving in the solid wastes is a function of the sulfur concentration of coal and the slurry concentration,[1,2] i.e.,

$$\frac{\text{lb makeup water}}{\text{lb sulfur}} = 5.9\left(\frac{1-m}{m}\right)$$

where

m = weight fraction of solids in waste

= (weight of solids)/(weight of solids plus water)

The above equation can similarly be modified to give the required daily water feed rate, W_{FGD}^{2}:

$$W_{FGD}^{2}, \text{ gal/day} = 1.7 \times 10^{4} \frac{P\dot{Q}}{Q} S \left(\frac{1-m}{m}\right)$$

The total required daily water feed rate is therefore given as

$$W_{FGD} = W_{FGD}^{1} + W_{FGD}^{2}$$

For the typical plant, application of the above equations gives

$$\begin{aligned} W_{FGD}^{1} &= 0.80 \times 10^{6} \text{ gal/day (vaporized)} \\ W_{FGD}^{2} &= 0.23 \times 10^{6} \text{ gal/day (50 percent solids)} \\ W_{FGD} &= 1.0 \times 10^{6} \text{ gal/day} \end{aligned}$$

On an annual basis,

$$\begin{aligned} W_{FGD} &= (0.486 \times 10^{6} \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 142 \times 10^{6} \text{ gal/yr} \end{aligned}$$

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 40-44.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 110-120.

㉑ Lime/Limestone Requirement for SO_2 Control

The amount of lime/limestone required for flue gas desulfurization is 32 x 10^3 tons of dry $CaCO_3$/yr. (The requirement is given solely in terms of limestone because of the relatively large economic penalty incurred if lime is purchased rather than obtained during calcination of limestone.)

For limestone scrubbing, absorbent utilization is generally 0.8[1] (i.e., the calcium-to-sulfur ratio is 1.25) and, as shown in item ㉓, Flue Gas, Figure 3, the scrubber has to achieve 70-percent removal efficiency to satisfy the SO_2 emission standard. The exact percentage of scrubber removal efficiency will be a function of the standards under which a particular plant must operate. The percentage removal and the limestone required can be expected to be less for plants operating under previous New Source Performance Standards and using low-sulfur coals. The limestone requirement is therefore given by

$$\begin{aligned} \text{Limestone} &= (1.25)(100/64)(SO_2 \text{ feed rate})(\text{scrubber efficiency}) \\ &= 1.25\ (100/64)(81 \text{ ton } SO_2/\text{day})(0.70) \\ &= 110 \text{ tons dry } CaCO_3/\text{day} \end{aligned}$$

where

100/64 = limestone/SO_2 molecular weight ratio.

On an annual basis,

$$\begin{aligned} \text{Limestone} &= (110 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 32 \times 10^3 \text{ tons/yr} \end{aligned}$$

Reference

1. Aerospace Corporation, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-044b, March 1978.

㉒ Solid Waste Handling

The typical plant and associated pollutant controls generate 177 x 10^3 tons/yr (dry basis) of solid sludge.

Solid waste streams requiring a disposal site contain bottom ash sluiced from the boiler and fly ash from the precipitator, which has been combined with dewatered scrubber sludge to form a material suitable for dry disposal. A portion of the fly ash (≈25 percent) not required in the fixing process for the scrubber sludge disposal system can be stored in hoppers for sale as a building material. The amount of fly ash required in the sludge disposal process will depend on the content of unreacted limestone in the sludge, the alkalinity of the ash, the moisture in the sludge, and the desired properties of the fixed material. In some instances, all the fly ash plus the addition of lime may be necessary to properly fix the sludge material.[1,2]

Bottom ash is disposed of in a lined ash pond from which water is recycled to operate the ash sluicing system. The ash material settles in the pond to approximately 50 percent solids.

This impoundment is formed by the excavation of the disposal site. Sides of the impoundment are sloped and extend above grade level to complete the basin and form berms and dikes around the periphery of the site. A total depth of 30 ft of waste material is considered typical.

When dry fly ash is mixed with the scrubber sludge, which has been dewatered to 20 percent water, the resulting mixture will dry to form material that has good mechanical stability and high resistance to leaching. The material resembling a low grade of cement, can be piled and graded in the disposal site to form the desired contour so as to promote proper drainage and prevent erosion. Under weather and soil conditions existing in much of the Great Plains area, no topsoil cover of the disposal site may be necessary after proper grading, contouring, and compaction. Under these conditions, the disposal site can be any area within the facility where the material can be handled and distributed suitably. No special subsoil conditions or site liner should be required.

For the typical plant, determination of total solid wastes on a dry basis and required land area are as shown in Table 3.

Table 3. Determination of Total Solid Wastes

1.

115 tons/day	bottom ash
345	fly ash (75 percent of total)
124	reacted limestone (75%:$CaSO_3 \cdot \frac{1}{2} H_2O$ & 25%:$CaSO_4 \cdot 2 H_2O$)[1]
+22	unreacted limestone
606 tons/day	(solids, dry) at 88.6 lb/ft^3

Adding sluicing water for bottom ash and 20 percent water remaining in sludge results in

115 tons/day	(sluicing water)
30	(water in sludge)
750 tons/day	wet bottom ash and fly ash - scrubber sludge mixture

2. To determine land required:*[2]

$$\left(750\ \frac{\text{tons}}{\text{day}}\right)\left(2000\ \frac{\text{lb}}{\text{ton}}\right)\left(\frac{1}{88.6}\ \frac{\text{ft}^3}{\text{lb}}\right)\left(\frac{1}{30}\ \text{ft} \times \frac{1}{43,560}\ \frac{\text{acre}}{\text{ft}^2}\right)$$

$$\left(1.1,\ \text{impoundment size factor}\right)\left(365\ \frac{\text{days}}{\text{year}}\right) = 5.2\ \frac{\text{acres}}{\text{year}}$$

3. This results in a land acreage requirement of

$$\left(5.2\ \frac{\text{acres}}{\text{year}}\right)\left(30\ \frac{\text{years}}{(\text{life})}\right) = 156 \text{ acres at 100 percent capacity factor}$$

* Assumes a 30-ft depth of material for both the bottom ash pond and the dry sludge disposal sites.

On an annual basis,

Sludge = (606 tons/day)(0.8 capacity factor)(365 days/yr)
= 177 x 10^3 tons/yr

and

Land requirement = (156 acres/yr)(0.8 capacity factor)
= 125 acres for 30 years, 30 feet deep

Three alternative sludge disposal or treatment and stabilization methods are available for disposal of the wastes: (1) Simply ponding the sludge and the fly ash, if it were not saleable, with the bottom ash in a pond that could be drained in sections and covered with soil. (2) Settling the wastes over an impervious layer and decanting of supernatant liquid; the impervious material can be clay or an elastomeric liner with a permeability coefficient of 10^{-7} cm/sec or less. (3) Installing an underdrainage or dewatering system of perforated pipes in the soil immediately below the sludge-soil interface. Settling of the wastes up to 60 percent solids has been observed.[2] Further settling to 80 percent solids (with a correspondent reduction of waste volume and disposal land area) can be achieved if the scrubber sludge were oxidized to gypsum within the scrubber or in an oxidation tower downstream of the scrubber.

Decisions on the use of these alternatives will be based on site-specific considerations, including sludge and soil characteristics, land reclamation requirements, and cost factors.

Radon Emanation From Solid Waste Storage

Analysis of the ash produced by the combustion of Northern Great Plains subbituminous coal has shown that the typical power plant burial site for solid waste will emit approximately 4.47×10^{-4} Ci/day of radioactive radon-222 gas for every acre of covered solid waste disposed of. Over a 30-yr plant lifetime, radon emissions will average 2.8×10^{-2} Ci/day for a typical 500-MWe plant, assuming that all of the solid wastes are buried with approximately 2 ft of earth cover at the power plant site and the plant operates at an average capacity factor of 80 percent.

Radon emanation from ash piles is a function of the concentrations of radium-226 in the waste material, surface area and depth of the buried waste, and the depth of earth cover over the waste. Using data collected by the U.S. Geological Survey,[3] Goldman has shown that the annual radon-222 gas emissions from Northern Great Plains coal ash waste with a radium-226 concentration of 2.95 pCi/gm would be 0.215 Ci/yr for every acre of uncovered ash waste piles.[4] Waste containing radium-226 (the parent nuclide of radon-222 gas) buried at a depth of 10 ft will emit approximately the same amount of radon gas as waste buried in deeper layers because of the self-shielding effect of the waste.

Using these data, a radon gas emanation rate factor of 5.89×10^{-4} Ci/day-acre is produced, assuming no earth cover and an ash depth of at least 10 ft. This factor must be adjusted downward according to the amount of non-ash waste, e.g., scrubber sludge, in the solid waste piles.

Because radium-226 decays to radon-gas at a very slow rate (the half-life of radium-226 is over 1600 yr), it can be assumed that, over the 30-yr plant life, radon gas emanation is directly proportional to the waste pile surface area and the amount of ash containing radium-226 in the waste; therefore,

$$\text{Radon gas, Ci/day} = \left(\frac{\text{ash content in solid waste}}{\text{total solid waste disposed}}\right)\left(\begin{matrix}\text{surface area of}\\ \text{waste piles, acres}\end{matrix}\right) \times (\text{radon emanation factor})$$

It has been shown that, the total area necessary for the disposal of solid wastes at a depth of 30 ft over the 30-yr lifetime for the typical 500-MWe plant, assuming an 80-percent capacity factor, is 125 acres. Therefore, the average daily radon emission from the burial site over the 30-yr plant life is as follows:

$$\text{Radon gas} = \left(\frac{460\ \text{tons/day}}{606\ \text{tons/day}}\right)\left(\frac{125\ \text{acres}}{2}\right)\left(0.589 \times 10^{-3}\ \text{Ci/day-acre}\right) = 2.8 \times 10^{-2}\ \text{Ci/day}$$

The factor of 2 is used to compute the average area of the solid waste burial ground assuming a constant buildup at 10 acres/yr over 30 yr.

Therefore, the annual average radon emission, assuming a 80-percent capacity factor, is

$$\text{Annual radon gas} = (2.8 \times 10^{-2}\ \text{Ci/day})\,(0.8)(365\ \text{days/yr}) = 10.2\ \text{Ci/yr}$$

References

1. P.P. Leo and J. Rossoff, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact," EPA-600/7-78-044b, Aerospace Corporation, March 1978.
2. R.B. Fling et al., "Disposal of Flue Gas Cleaning Wastes: EPA Shawnee Field Evaluation - Third Annual Report," EPA-600/7-80-011, Aerospace Corporation, January 1978.

3. V.E. Swanson, "Collection, Chemical Analysis, and Evaluation of Coal Samples," USGA Open File Report 76-468, 1975.
4. M.I. Goldman, "Energy: What About the Waste?" Chemical Engineering Progress, November 1979, p. 65.

㉓ Flue Gas

The pollutants and trace elements that are part of the flue gas emitted to the ambient atmosphere, after control, are as follows:

SO_2	7.15×10^3 tons/yr
NO_x	10.2×10^3 tons/yr
TSP	0.525×10^3 tons/yr
HC	0.320×10^3 tons/yr
CO	1.05×10^3 tons/yr
CO_2	3.7×10^6 tons/yr
As	128 lb/yr
Be	Unknown
Cd	11.7 lb/yr
Mn	0.6 lb/yr
Pb	32.1 lb/yr
Se	2.0 lb/yr
U	718.0 lb/yr
Zn	286.0 lb/yr
Ra-226	1.4×10^{-3} Ci/yr (radioactive)

$\underline{SO_2}$

The amount of SO_2 emitted to the ambient atmosphere for this unit and the coal characteristics selected is 0.42 lb/10^6 Btu. The current New Source Performance Standards for SO_2 regulation are summarized below.[1]

Uncontrolled Emissions (lb $SO_2/10^6$ Btu)	Percent Reduction	Controlled Emissions (lb $SO_2/10^6$ Btu)
> 12	> 90	1.2 maximum
12 to 6	90	1.2 → 0.6
6 to 2	90 → 70	0.6 (constant)
< 2	70	< 0.6

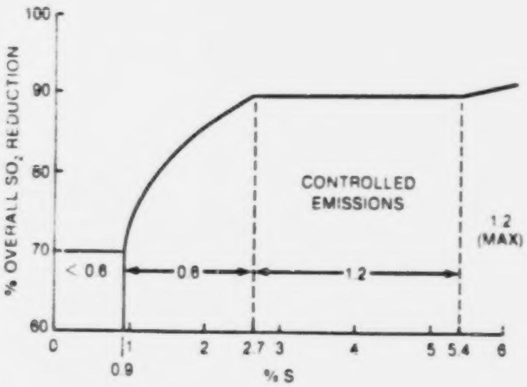
Basically, for steam coals burned by utilities with uncontrolled emissions exceeding 1.2 lb $SO_2/10^6$ Btu, SO_2 reductions exceeding 90 percent would be required to limit emissions to a maximum of 1.2 lb $SO_2/10^6$ Btu. For those coals whose uncontrolled emissions would range from 12 to 6 lb/10^6 Btu, a constant 90-percent removal is required, resulting in controlled emissions ranging from 1.2 lb $SO_2/10^6$ Btu to 0.6 lb/10^6 Btu. For coals with sulfur contents that would emit 6 to 2 lb $SO_2/10^6$ Btu, a variable removal rate between 90 and 70 percent is required to achieve a constant 0.6 lb $SO_2/10^6$ Btu. For example, at 6 lb $SO_2/10^6$ Btu, 90-percent removal is required; at 2 lb $SO_2/10^6$ Btu, 70 percent is required; and at 3 lb $SO_2/10^6$ Btu, 80 percent is needed. In all cases, it should be noted that the controlled emissions are 0.6 lb/10^6 Btu. If the uncontrolled emissions are less than 2 lb/10^6 Btu, 70 percent SO_2 removal is then required.

On a yearly basis, controlling SO_x to 0.42 lb/10^6 Btu gives (at 80-percent capacity factor),

$$\boxed{\begin{aligned} SO_x &= (0.42\ \text{lb}/10^6\ \text{Btu})(34 \times 10^{12}\ \text{Btu/yr}) \\ &= 14.3 \times 10^6\ \text{lb/yr} \\ &= 7.15 \times 10^3\ \text{tons/yr} \end{aligned}}$$

The SO_2 removal requirements for a 8100 Btu/lb coal are illustrated in Figure 3. Seventy percent SO_2 removal is required up to a sulfur content of 0.9 percent. Between 2.7 and 5.4 percent, 90-percent removal is required. If the sulfur content is in the range between 0.9 and 2.7, different removal rates, as shown, are required to maintain the 0.6 lb $SO_2/10^6$ allowable. For the coal used in this ECIR (0.63 percent sulfur and 8100 Btu/lb), 70-percent SO_2 removal is needed because the coal falls below the 0.9-percent level. With a total of 10 percent sulfur removed as a result of sulfur retained in the bottom ash and fly ash, the sulfur content as seen by the scrubber is 0.57 percent (0.63 - 0.1 x 0.63). The scrubber will still be required to remove 70 percent to satisfy current regulatory requirements.

Figure 3. Overall SO_2 Reduction Required for a 8100 Btu/lb Coal to Meet Current NSPS Regulations



NO_x

The current New Source Performance Standard for NO_x regulations is[1] 0.6 lb/10^6 Btu.

The amount of NO_x emitted to the ambient atmosphere is 0.6 lb/10^6 Btu. The general way of achieving compliance with NO_x emissions is to employ combustion modification techniques.[2,3] The boiler manufacturer usually includes in his performance guarantee the provision that emissions of nitrogen oxides while firing coal shall be less than 0.6 lb/10^6 Btu.[4] Emissions of oxides of nitrogen are limited by low flame and furnace temperatures, by short residence time of the gases at high temperatures, and by reduced amounts of excess air present in the flame.

Particulates

The current New Source Performance Standard for particulate regulation is 0.03 lb/10^6 Btu.

The amount of particulates (i.e., fly ash that is not captured in the electrostatic precipitator or in the scrubber/mist eliminator) emitted to the ambient atmosphere is 0.03 lb/10^6 Btu. The amount of ash in the coal used in this ECIR is 8.0 percent. If 80 percent of the ash is emitted as fly ash and the electrostatic precipitator efficiency is 99.6 percent and an additional 5 percent or more of particulate material passing the precipitator is removed in the SO_2 scrubber, the particulate emission to the atmosphere is given by

$$\text{Particulates} = [(\text{ash fraction in coal})(\text{fly ash fraction})(\text{coal feed rate})(1\text{-electrostatic precipitator efficiency})]0.95$$

For the typical plant,

$$\begin{aligned}\text{Particulates} &= [(0.08)(0.80)(7.2 \times 10^3 \text{ tons/day})(1-0.996)]0.95 \\ &= 1.8 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Particulates} &= (1.8 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 525 \text{ tons/yr}\end{aligned}$$

On a yearly basis, controlling particulates (TSP) to 0.03 lb/10^6 Btu gives (at 80-percent capacity factor),

$$\begin{aligned} \text{TSP} &= (0.03\ \text{lb}/10^6\ \text{Btu})(34 \times 10^{12}\ \text{Btu/yr}) \\ &= 1.02 \times 10^6\ \text{lb/yr} \\ &= 510\ \text{tons/yr} \end{aligned}$$

Carbon Monoxide and Hydrocarbons

There are no New Source Performance Standards for carbon monoxide (CO) or hydrocarbons (HC). The amounts of CO and HC emitted to the ambient atmosphere are 3.6 tons/day and 1.1 ton/day, respectively. The emission factors for CO and HC are 1 lb/ton coal burned and 0.3 lb/ton coal burned, respectively.[5] Hence, the daily emissions of these pollutants are given by

$$\text{CO, HC} = (\text{emission factor})(\text{coal feed rate})$$

For the typical plant,

$$\begin{aligned} \text{CO} &= (1\ \text{lb/ton})(7.2 \times 10^3\ \text{tons/day})/2 \times 10^3\ \text{lb/ton} \\ &= 3.6\ \text{tons/day} \end{aligned}$$

$$\begin{aligned} \text{HC} &= (0.3\ \text{lb/ton})(7.2 \times 10^3\ \text{tons/day})/2 \times 10^3\ \text{lb/ton} \\ &= 1.1\ \text{tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{CO} &= (3.6\ \text{tons/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 1050\ \text{tons/yr} \end{aligned}$$

$$\begin{aligned} \text{HC} &= (1.1\ \text{tons/yr})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 320\ \text{tons/yr} \end{aligned}$$

An indication of the completeness of a combustion process is the concentration of carbon monoxide (and, to a lesser extent, hydrocarbon concentration). As such, pulverized coal-fired boilers have negligible emissions of carbon monoxide and hydrocarbons. Careful monitoring of excess air and temperature in the boiler ensures that the emissions of these pollutants are low.[6]

Trace Elements

Atmospheric emission rates for the trace elements are calculated to be (see Appendix B, Trace Element Analysis):

Element	lb/day at 100% capacity factor	lb/yr at 80% capacity factor
As	0.44	128.0
Be	Unknown	-
Cd	0.04	11.7
Mn	0.0002	0.6
Pb	0.11	32.1
Se	0.007	2.0
U	2.46	718.0
Zn	0.98	286.0

The trace elements are species found in small quantities in the raw coal. They become distributed among the bottom ash slag or the fly ash and flue gases. In the latter, some are emitted past the precipitator and enter the atmosphere. Because many trace elements exhibit preferential concentrations in the smaller particles emitted, about 5 percent of the initial concentrations of most trace elements are emitted to the ambient atmosphere.[7] Based on recent work at Lawrence Livermore Laboratory, a method was developed to calculate trace element emissions to the atmosphere. The generalized methodology, algorithm, and associated references for calculating trace element emissions are given in Appendix B, Trace Element Analysis.

Carbon Dioxide

The amount of CO_2 emitted to the ambient atmosphere is 12.5×10^3 tons/day. During the combustion of bituminous coal, 0.21 lb CO_2 are emitted to the atmosphere for every 10^3 Btu generated.[8] Hence,

$$\boxed{(CO_2)_{COMB} = \text{(emission factor)(coal feed rate)(heat content of coal)}}$$

For the typical plant,

$$\boxed{\begin{aligned}(CO_2)_{COMB} &= (0.21\ \text{lb}/10^3\ \text{Btu})(4.9 \times 10^3\ \text{tons/day})(12 \times 10^3\ \text{Btu/lb}) \\ &= 12.3 \times 10^3\ \text{tons/day}\end{aligned}}$$

Additionally, a small amount of CO_2 is released to the atmosphere from the limestone reaction with the SO_2.[9] This amount is estimated as follows:

$$\boxed{\begin{aligned}(CO_2)_{LIMESTONE} &= \left(\begin{matrix}\text{110 tons/day, limestone into} \\ \text{scrubber}\end{matrix}\right)\left(\frac{44}{100},\ \begin{matrix}\text{molecular weight} \\ \text{of } SO_2/CaCO_3\end{matrix}\right) \\ &= 0.048 \times 10^3\ \text{tons/day}\end{aligned}}$$

The total amount of CO_2 emitted to the atmosphere is given by

$$\begin{aligned} CO_2 &= (CO_2)_{COMB} + (CO_2)_{LIMESTONE} \\ &= 12.3 \times 10^3 \text{ tons/day} + 0.048 \times 10^3 \text{ tons/day} \\ &= 12.35 \times 10^3 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} CO_2 &= (12.35 \times 10^3 \text{ tons/day})\ (0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 3.6 \times 10^6 \text{ tons/yr} \end{aligned}$$

Radionuclides

Analysis of the fly ash produced by combustion of western subbituminous coal has shown that a typical 500-MWe plant will discharge into the atmosphere approximately 4.94×10^{-6} Ci/day of radioactive radium-226.

Because over 80 percent of the trace radioactive particles in coal remain with the fly ash after combustion, removal of the fly ash by electrostatic precipitators is the most effective control technology available.[10] Samples from the combustion of Northern Great Plains coal were analyzed for its radium content by the U.S. Geological Survey with the following results.[10]

Concentration of Radioactive Elements in Fly Ash

Radium-226	2.95×10^{-12} Ci/gm	or	1.34×10^{-9} Ci/lb

Other trace radioactive elements are emitted, e.g., thorium and uranium, but pose a much smaller health hazard than radium.

Assuming the total activity released to the environment is through the fly ash escaping the electrostatic precipitators, the daily release of any radioactive isotope may be calculated as follows:

$$\begin{aligned} \text{Activity of isotope i, Ci/day} = &\ (\text{concentration of isotope i in fly ash}) \\ &(\text{fly ash generated, tons/day}) \\ &(2000 \text{ lb/ton})(1\text{-}ESP_{EFFICIENCY}) \end{aligned}$$

For the typical plant,

$$\begin{aligned} \text{Radium-226} &= (1.34 \times 10^{-9} \text{ Ci/lb})(461 \text{ tons/day})(2000 \text{ lb/ton})(1-0.996) \\ &= 4.94 \times 10^{-6} \text{ Ci/day} \end{aligned}$$

On a yearly basis,

$$\text{Radium-226} = (4.94 \times 10^{-6}\ \text{Ci/day})(0.8\ \text{capacity factor})(365\ \text{days/yr})$$
$$= 1.4 \times 10^{-3}\ \text{Ci/yr}$$

To date, there are no regulations that apply to the release of radioactive pollutants from coal-fired power plants.

References

1. Federal Register, Vol. 44, No. 113, 40 CFR Part 60, "New Sources Performance Standards; Electric Utility Steam Generating Units," June 11, 1979.
2. J. Ando, "NO_x Abatement for Stationary Sources in Japan," EPA-600/7-79-205, August 1979.
3. National Academy of Sciences, "Air Quality and Stationary Source Emission Control," prepared for the Committee on Public Works, U.S. Senate, Serial No. 94-4, 1975.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978.
5. U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," 2nd edition, EPA AP-42, 1975.
6. Final Environmental Impact Statement, Spurlock Station, Unit No. 2 and Associated Transmission, USDA-REA-EIS-76-4F, November 1976.
7. K.K. Bertin and E.D. Goldbert, Science, Vol. 183, p. 233, 1971.
8. U.S. Department of Energy, "CO_2 Emissions from Synthetic Fuels Energy Sources," August 8, 1979, p. 2, Table 1.
9. Aerospace Corporation, Estimation, April 1980.
10. V.E. Swanson, "Collection, Chemical Analysis, and Evaluation of Coal Samples," USGA Open File Report 76-468, 1975.

III. PHYSICAL REQUIREMENTS

Large amounts of land and water resources are required for a coal-fired power plant. The section on Water summarizes the requirements and uses of makeup water discussed in Section II. The section on Land discusses the land needed for plant siting and solid waste disposal.

Water

The maximum makeup water requirement estimated for the typical plant operating at 80-percent capacity factor is 1.7×10^9 gal/yr. Some of this water is recovered, treated in the water treatment facility, and recycled back to the plant (see Section II, item ⑭, Recycled Water and Plant Discharges). The remainder is obtained from local water sources and is lost primarily through evaporation and drift losses in the cooling towers, holding-pond surface losses, and dust suppression systems. The major uses of makeup water are listed in Table 4.

Land

The sizes of actual power plant sites vary over a considerable range and depend on a number of factors such as utility preference, cost of land, waste disposal requirements, plant location, and the capacity of the plant. Although there is not a strong link between site size and the particular features of the plant (such as MWe), broad relationships exist. For western plants in the 500-MWe and larger range, site sizes will vary from about 1000 to 2000 acres. There are a number of older, smaller plants operating on much smaller sites, but they should not be considered typical for new western plants.

Because the land needed for buildings is a relatively small portion of the site, the bulk of the site is needed for coal storage, raw water storage, onsite waste disposal, water recycle facilities, and general working room. Solid waste disposal area for a plant similar to the typical plant was estimated at 125 acres (30-ft depth) for the 30-yr lifetime of the plant (see Section II, item ㉒, Solid Waste Handling).[1] If ash and sludge are disposed of offsite (e.g., placed back in the mine), then approximately 400 acres less will be required for the power plant site.[2]

The actual coal preparation facilities at the surface mine site will be minimal for initial screening and crushing and will normally be included in the site area for the mine excavation. The refuse from the preparation plant will typically be placed back in the mine pit as part of the fill; thus, there will be no land requirement for disposal of preparation wastes.[3]

Table 4. Consumptive Water Demands by Major Plant Processes and Major Water Recycle Streams (at 80-Percent Capacity Factor)

Source	Environmental Point of Interest on Flow Chart	Estimated Quantity (gal/yr)
Raw water storage evaporation	⑬	0.028×10^9
Cooling tower evaporation and drift loss	⑩	1.4×10^9
SO_2 scrubber evaporation and sludge retention	⑳ and ㉒	0.145×10^9
Bottom ash quenching and transport loss	⑯	0.004×10^9
Soot blowing and plant steam losses	⑯	0.020×10^9
Total estimated water consumption/demand		1.6×10^9
Source of Water for Recycling		
Cooling tower blowdown	⑭	0.15×10^9
Boiler blowdown	⑭	0.02×10^9
General plant drains and water treatment wastes	⑭	0.03×10^9
Total recycle water flow		0.20×10^9

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA-450/2-78-007a, pp. 6-18, July 1978.
2. Final Environmental Impact Statement, "Missouri Basin Power Project (Wheatland Generating Station Units 1, 2, and 3 and Associated Transmission, and Grayrocks Reservoir)," USDA-REA-EIS(ADM)76-2-F, May 1976.
3. Personal Communication, Phillip Halch, Roberts and Schaefer Engineers and Contractors, April 1980.

IV. PERSONNEL

Although the number of people required for the operation and planned maintenance of a power plant is highly dependent on the philosophy of the particular utility, certain guidelines are used. One such is 0.089 persons/MWe for each shift.[1] This number, which includes support personnel and personnel for operating and maintaining pollution control equipment, equates to 45 persons per shift or 135 persons total per day for a 500-MWe plant.

In addition to the above requirement, personnel will be needed for coal preparation and shipment. Although staffing levels vary at various coal production facilities, 10 personnel per shift for the coal screening facility and the unit-train loading and unloading facility or a total of 20 personnel per 2-shift day are required to operate the coal preparation and supply function for the power plant.[2]

References

1. Personal Communication, John W. Holt, Jr., Power Plants Branch, Rural Electrification Administration, Washington, D.C., April 1980.
2. Mitre Corp., "Resource and Land Investigations (RALI) Program: An Approach to Environmental Assessment With Application to Western Coal Development," August 1975, p. IV-11.

V. OCCUPATIONAL SAFETY AND HEALTH

Occupational safety and health implications of coal-fired power plants have been examined using actual death and injury statistics.[1] For coal processing plants, the report lists (per 10^8 tons processed) 1.7 to 2.7 deaths and 98 to 159 injuries. The corresponding figures for power plant workers (per 10^{12} Btu output) are 0 to 0.0095 deaths and 0.16 to 0.19 injuries.

For the plant assumed in this ECIR, the amount of coal processed is 1.96 x 10^6 tons/yr and 0.16 x 10^6 tons/10^{12} Btu. The output of the plant is 12 x 10^{12} Btu/yr. Thus, the projected deaths and injuries from accidents for the plant are as follows:

	Preparation Plant		Power Plant	
	Annual	Per 10^{12} Btu	Annual	Per 10^{12} Btu
Deaths	0.0033-0.0053	0.0003-0.0004	0-0.11	0-0.0095
Injuries	1.9-3.1	0.16-0.26	1.9-2.3	0.16-0.19

Reference

1. S.C. Morris, K.M. Novak, and L.D. Hamilton, "Health Effects of Coal in the National Energy Plan," Brookhaven National Laboratory, BNL-51043, April 1979, pp. 8-9.

APPENDIX A. AIR EMISSIONS UNDER VARIOUS REGULATORY AND CONTROL TECHNOLOGY ASSUMPTIONS

The air emissions calculated for the coal-fired power plant described in this document are based on current Federal NSPS for coal-fired power plants using bituminous coal and that commenced construction after September 18, 1978. The units coming on line now and for several years into the future are generally subject to the previous Federal NSPS. There are also many units now operating that were under constructon or operating prior to the effective date of the previous NSPS and are therefore not subject to any Federal NSPS. Although these plants are subject to Federal NSPS less stringent than the current regulation, they will in many instances be subject to more stringent state and local air emission regulations. In many instances, the new plants, subject to current Federal NSPS, will also be subject to more stringent state or local standards that will effectively establish the allowable air pollutant emission levels. Table A-1 provides a summary of air emissions under current NSPS and previous NSPS, as well as emissions from uncontrolled plants.

It should also be noted that under the previous NSPS and uncontrolled assumptions, coals having low-sulfur content could be used to reduce SO_2 emissions and to thus comply with the NSPS standard. The new NSPS do not allow the use of low-sulfur coal alone as an SO_2 control for new plants.

In addition to impacts on air emissions, the use of a limestone or lime scrubber generates a varying amount of solid waste (scrubber sludge). As SO_2 removal requirements increase, the amount of scrubber sludge will increase (see item ⑲, Sludge From SO_2 Control). Solid wastes will also be increased if a higher ash coal is selected (see item ⑱, Fly Ash From Particulate Control).

Table A-1. Air Emissions Under Various Regulatory Assumptions*

Federal Regulation	Firing Rate - 34 x 10^{12} Btu/yr**		
	SO_2	NO_x	Particulate
Current NSPS As of 6/11/79	0.6 lb/10^6 Btu 10.2 x 10^3 tons/yr	0.6 lb/10^6 Btu 10.2 x 10^3 tons/yr	0.03 lb/10^6 Btu 0.50 x 10^3 tons/yr
Previous NSPS 12/23/71 to 6/11/79	1.2 lb/10^6 Btu 20.4 x 10^3 tons/yr	0.7 lb/10^6 Btu 11.9 x 10^3 tons/yr	0.1 lb/10^6 Btu 1.7 x 10^3 tons/yr
Uncontrolled emissions	85 x 10^3 tons/yr	***"Normal firing" @ .82 lb/10^6 Btu 13.9 x 10^3 tons/yr	50% mechanical removal of fly ash 50 x 10^3 tons/yr

* Based on the plant assumed in this ECIR, using a coal with 3.3 percent sulfur content.

**"Firing rate" is the heat content of all the coal fed into the boiler during 1 year.

*** U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978, p. 6-9.

APPENDIX B. TRACE ELEMENT ANALYSIS

Trace elements are species that are found in small quantities in a mineral. During coal combustion, they become distributed among slag, fly ash, or gases and may be emitted into the environment. Based on industrial experience with pulverized coal boilers, it is generally accepted that 80 percent of the ash present in coal is charged as fly ash, while only 20 percent is discharged as bottom ash.[1,2] Because many trace elements exhibit preferential concentrations in the smaller particles emitted from coal-fired power plants,[3-6] about 5 percent of the initial concentrations of most trace elements pass the ESP and can be emitted to the atmosphere if not collected in a downstream SO_2 scrubber.[7] In addition, due to the nonhomogeneity of coal, the composition and concentration of combustion products will vary with coal. However, based on recent work conducted by Lawerence Livermore Laboratory, it is possible to quantitatively estimate trace element concentrations penetrating the ESP if certain system operating parameters and coal composition are known.[8] An explanation of how this is done follows.

Needed information:

- Trace element concentrations in coal being fired (C_i, i=1, 2, ... n, μg/g)
- Coal feed rate (F, g/sec)
- Plant net power output (P, watts)
- Overall thermal efficiency (η_p)
- Electrostatic precipitator overall efficiency (η_{ESP})

Definitions:

plant total power input = (plant net power output)/(overall thermal efficiency)

= P/η_p

(consumption rate)$_i$ = (trace element i concentration in coal) (coal feed rate)/(plant total power input)*

= $(C_i)(F)/P/\eta_p)$

---

* Note: 1 watt = 1 joule/second.

ESP efficiency ratio = (1-ESP overall efficiency)/(1-ESP overall efficiency used in LLL study)

= $(1-\eta_{ESP})/(1-0.97)$

(atmospheric emission rate)$_i$ = (stack emission of trace element i)/(plant total power input)

(AER)$_i$ = unknown to be determined

(penetration)$_i$ = (100%) (atmospheric emission rate)$_i$/(consumption rate)$_i$

= given in following Table B-1

Procedure:

1. When the needed information is obtained, determine
   - plant total power input
   - (consumption rate)$_i$
   - ESP efficiency ratio

2. Obtain (penetration)$_i$ from Table B-1

3. (atmospheric emission rate)$_i$ = (penetration)$_i$(consumption rate)$_i$ (ESP efficiency ratio)/100

$$\boxed{\begin{gathered}(\mathrm{AER},\ \mu g/J)_i = (\mathrm{penetration})_i\,[(C_i)(F)/(P/\eta_p),\ \mu g/J] \\ (1-\eta_{ESP})/[(1-0.97)]\end{gathered}}$$

For the typical plant a representative western low-sulfur subbituminous coal was chosen.[9,10] Trace element concentrations of this typical western (Wyoming-Wyodak) coal are listed as follows:

Element	Concentration (μg/g)
As	2.0
Be	Detected
Cd	1.8
Mn	0.01
Pb	1.0
Se	0.05
U	35.00
Zn	8.2

To find the atmospheric emission rates for the trace elements, the following information is used:

P = 500 x 10^6 watt
η_p = 35 percent
F = 75.6 x 10^3 gm/sec
η_{ESP} = 99.6 percent

Table B-1. Penetration of Elements Contained in Particles Emitted From an ESP-Equipped Coal-Fired Generating Unit (%)

Element	ESP Unit[a]	Element	ESP Unit[a]
Al	1.1 ± 0.1	Mo	5.1 ± 1.2
As	11.5 ± 3.0	Mn	1.6 ± 0.5
Ba	4.0 ± 0.8	Na	1.55 ± 0.09
Be	0.9 ± 0.3	Pb	5.5 ± 1.1
Br	0.14 ± 0.08	Rb	1.3 ± 0.1
Ca	1.3 ± 0.2	Sb	7.7 ± 0.7
Cd	8.8 ± 3.0	Sc	1.46 ± 0.06
Ce	1.29 ± 0.09	Se	7.7 ± 0.8
Co	2.5 ± 0.3	Sr	2.0 ± 0.3
Cr	3.8 ± 0.3	Ta	1.3 ± 0.1
Cs	1.2 ± 0.2	Th	1.32 ± 0.08
Fe	1.32 ± 0.09	Ti	1.51 ± 0.03
Ga	4.4 ± 0.7	U	3.7 ± 0.4
In	5.4 ± 0.7	V	3.7 ± 0.6
K	1.0 ± 0.3	W	7.2 ± 2.2
La	1.29 ± 0.07	Zn	6.3 ± 0.8
Mg	1.2 ± 0.4	Zr	1.4 ± 0.3

---

[a] Number of samples was eight unless otherwise indicated.

The atmospheric emission rate for arsenic is therefore

$$
\begin{aligned}
(AER)_{As} &= \left[\frac{(\text{penetration})_{As}\ (C_{As})(F)}{(P/\eta_p)}\right]\left[\frac{1-ESP}{1-0.97}\right] \\
&= \left[\frac{(0.115)(2.0\ \mu g/g)(75.6 \times 10^3\ g/s)}{500 \times 10^6\ J/s\ /\ 0.35}\right]\left[\frac{1-0.996}{1-0.97}\right] \\
&= 1.6 \times 10^{-6}\ \mu g/J
\end{aligned}
$$

On a daily basis,

$$(AER)_{As} = \frac{(2.83 \times 10^{-6}\ \mu g/J)(1.055 \times 10^{3}\ J/Btu)(0.117 \times 10^{12}\ Btu/day)(1 \times 10^{-6}\ g/\mu g)}{(0.454 \times 10^{3}\ g/lb)}$$

$$= 0.44\ lb/day$$

Daily atmospheric emission rates for the trace elements are as follows:

Element	lb/day at 100% capacity factor	lb/yr at 80% capacity factor
As	0.44	128
Be	Unknown	-
Cd	0.04	11.7
Mn	0.0002	0.6
Pb	0.11	32.1
Se	0.007	2.0
U	2.46	718.0
Zn	0.98	286.2

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. D.F.S. Natusch, J.R. Wallace, and C.A. Evans, Jr., Science, Vol. 183 No. 4121, pp. 202-4, 1974.
4. N.E. Bolton et al., "Trace Element Measurement at the Coal-Fired Allen Steam Plant, Progress Report, June 1971 - January 1973," ORNL-NSF-EP-43, March 1973.
5. N.E. Bolton et al., "Trace Element Measurements at the Coal-Fired Allen Steam Plant, Progress Report, February 1973 - July 1973," ORNL-NSF-EP-62, 1974.
6. G.E. Gordon et al., "Study of the Emissions from Major Air Pollution Sources and Their Atmospheric Interactions," University of Maryland Department of Chemistry and Institute for Fluid Dynamics and Applied Mathematics, College Park, Maryland, 1974.
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8. J.M. Ondov, R.C. Ragaini, and A.H. Biermann, "Emissions and Particle-Size Distributions of Minor and Trace Elements at Two Western Coal-Fired Power Plants Equipped with Cold-Side Electrostatic Precipitators," Environmental Science and Technology, Vol. 13, pp. 946-953, 1979.
9. Keystone, pp. 559.
10. Applications for Permit Submitted to the Wyoming Industrial Siting Council Regarding Construction of the Laramie River Generating Station, Burns and McDonnell Engineers, Kansas City, Missouri, 1975, pp. III-C-9.

GLOSSARY

Blowdown	Water that is periodically removed from either the cooling towers or the coal-fired boiler to prevent concentration of total dissolved solids.
Bottom ash	Noncombustible residues of coal combustion that are collected and removed from the boiler.
Capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.
Circulating water	Water supplied to the main condenser in the generating plant that is cooled by the cooling towers.
Cooling tower drift loss	Aerosols of water that are lost in the atmosphere from the cooling towers.
Cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.
Curie	An amount of radioactive material that decays at a rate of 3.7×10^{10} disintegrations per second.
Dead storage	Long-term storage in which the coal is typically compacted and sealed.
Electrostatic precipitator	Environmental control device used to remove a high percentage of the fly ash in the flue gas.
Flue gas	Gases generated from the combustion of fossil fuel in the boiler.
Flue gas desulfurization scrubbers	Environmental control device used to remove a high percentage of the sulfur dioxide in the flue gas.
Fly ash	Noncombustible residues of coal combustion that are carried out of the boiler in the flue gas.
Fugitive emissions	Unintentional emissions, such as blowing dust from a coal pile.
Net station heat rate ($\dot{Q}$)	Amount of fuel input (in Btu) necessary to generate 1 kWh of electricity.

Pyritic material	Metallic compounds of sulfur naturally occurring in coal.
Recycle water	Water that is collected, treated, and reused at the power plant.
Run-of-mine coal	Coal as it comes from the mine prior to sizing or other preparation.
Sludge	Wet residue of lime/limestone and sulfur that is generated in the flue gas desulfurization unit.

ACRONYMS AND ABBREVIATIONS

A	ash content in coal
AER_i	atmospheric emission rate of trace element i
As	arsenic
Be	beryllium
Btu	British thermal unit
C	carbon
$CaSO_3$	limestone
Cd	cadmium
Ci	curie
C_i	concentration of trace element i
Cl	chlorine
CO	carbon monoxide
CO_2	carbon dioxide
Cu	copper
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
η_p	overall thermal efficiency of plant
η_{ESP}	overall efficiency of electrostatic precipitator
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
F	feed rate of coal
Fe	iron
FGD	flue gas desulfurization
g	gram
gal	gallon
H	hydrogen
ha	hectare
HC	hydrocarbons
J	joule
kg	kilogram
kWh	kilowatt-hour
l	liter
lb	pound
mg	milligram (10^{-3} gram)
μg	micrograms (10^{-6} grams)
Mn	manganese
MWe	megawatt - electrical
MWt	megawatt - thermal
N	nitrogen
NO_x	nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
O	oxygen
P	net power delivered to the transmission grid
Pb	lead
Q	heat content of coal
$\dot{Q}$	net station heat rate
ROM	run-of-mine

s	second
S	sulfur
Se	selinium
SO_2	sulfur dioxide
te	tonne
TSP	total suspended particulates (air)
TSS	total suspended solids (water)
W_{BA}	total makeup water requirements for bottom ash handling
$W_{BLOWDOWN}$	amount of cooling tower blowdown
W_{DRIFT}	amount of drift loss from cooling tower
W_{EVAP}	amount of evaporation loss from cooling tower
W_{FGD}	makeup water for dust control of SO_2 scrubbers
W_{HAD}	amount of water needed for bottom ash handling and disposal
W_{TOW}	total makeup water requirements to the cooling towers
W_{VAP}	amount of evaporation loss from bottom ash hopper

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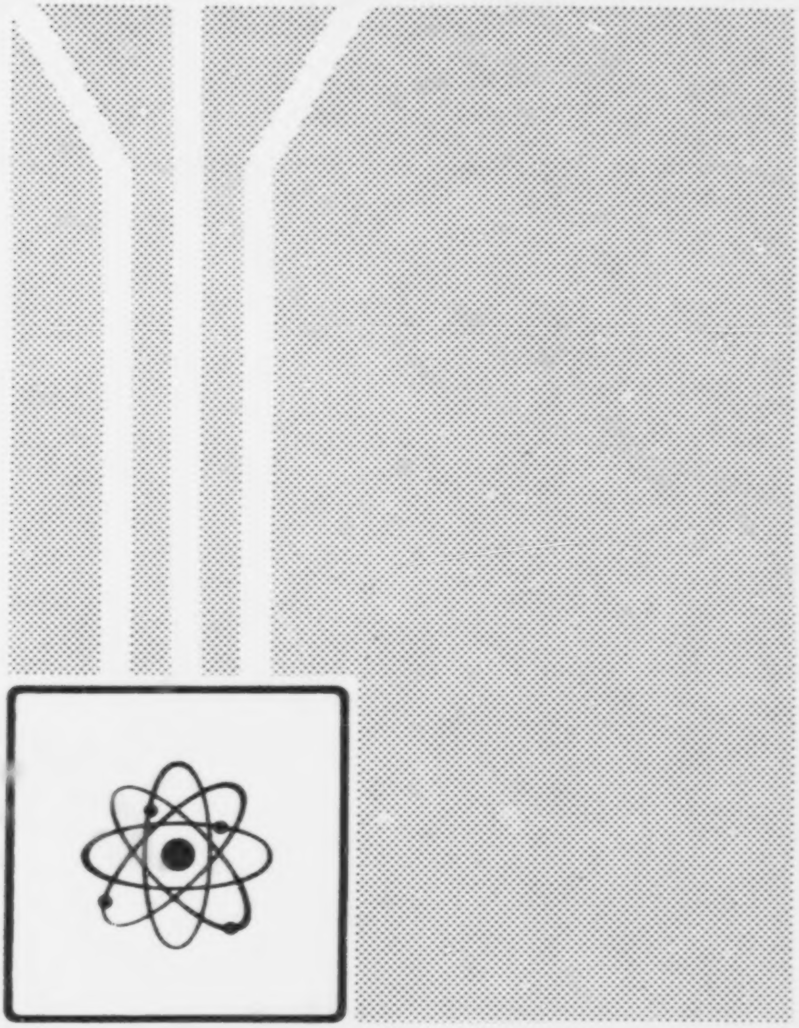
Pressurized Water Reactor Nuclear Power Plant

Environmental Characterization Information Report



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FOREWORD

This Environmental Characterization Information Report (ECIR) is a synthesis of environmental data and information relevant to a pressurized water reactor nuclear power plant. It is typical of a set of ECIRs that are being developed for a range of fossil, solar, geothermal, nuclear, and conservation energy systems. The ECIRs are designed to have several related purposes: to communicate to all potential users environmental data and information characteristic of an energy system; to present an organized data and information base for application in manual and computer-based analytical systems; and to provide the medium for facilitating development, maintenance, and critical review of the data and information base. The set of ECIRs is designed to replace the general technical backup volumes formerly supplied with "Environmental Data Energy Technology Characterizations," DOE/EV-0072, January 1980.

Responsibility for the contents and development of an ECIR is assigned to individual technology specialists in the Technology Assessments Division. This ECIR was developed under the direction of Dr. Neill Thomasson of the Nuclear Program Staff. In this endeavor, we also draw upon the technical support and assistance of qualified external experts familiar with the energy systems. Technical comments regarding this ECIR should be directed to Dr. Neill Thomasson, Project Officer, (301) 353-4327. Suggestions or recommendations for improving the ECIR concept should be addressed to me.

Dario R. Monti
Director, Technology Assessments
Division
Office of Environmental Assessments

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I. INTRODUCTION

There are currently four major manufacturers of nuclear steam supply systems in the United States: Westinghouse, Combustion Engineering, Babcock and Wilcox, and General Electric. The first three manufacturers build pressurized water reactors (PWR), i.e., the water in the reactor is maintained under high pressure to prevent boiling, and the steam to drive the main turbine is generated in a secondary loop by a steam generator.

The General Electric design uses a boiling water concept, i.e., steam to drive the main turbine is generated directly in the nuclear reactor. Because the characteristics of the plant operation and effluents (particularly radioactive effluents) differ from the pressurized water design, the boiling water reactor (BWR) will be discussed in a separate ECIR.

The "typical plant" selected for the main body of this Environmental Characterization Information Report (ECIR) is the Westinghouse design currently used in the Standardized Nuclear Unit Power Plant System (SNUPPS),[1] and unless otherwise stated, the information in this ECIR is based on the SNUPPS design. The reactor core in the SNUPPS plant is designed for a thermal output of 3411 MWt and an electrical output of 1188 MWe. The data presented in this ECIR have been normalized to 1000 MWe for ease of calculation, even though most modern nuclear power plants range from 1000 to 1300 MWe. For those few instances in which scaling by power is not strictly correct, the error is no greater than 16 percent. No attempt has been made to standardize the use of significant figures in this report.

SNUPPS was chosen as representative of modern pressurized water reactor designs for the following reasons:

- SNUPPS is the first attempt by a group of utilities to standardize a nuclear power plant design and to have it generically reviewed for licensing by NRC,
- The majority of PWRs are Westinghouse designs, and
- SNUPPS is a modern design and is representative of a nuclear plant that might be built by most utilities.

A future update of this ECIR will discuss differences among the Westinghouse, Babcock and Wilcox, and Combustion Engineering designs.

It is assumed that the typical plant will store its spent reactor fuel onsite indefinitely (i.e., no high-level waste disposal or spent fuel disposal site is available) and that other radioactive wastes will be processed and recycled to the maximum extent possible in keeping with the as-low-as-reasonably-achievable (ALARA) principle established in Nuclear Regulatory Commission regulations. The majority of potential gaseous radwaste effluent streams are filtered or otherwise treated prior to release into the environment.

Reference

1. "Standardized Nuclear Unit Power Plant System (SNUPPS)," Final Safety Analysis Report, October 2, 1979.

II. SUMMARY

This Environmental Characterization Information Report (ECIR) for a Pressurized Water Reactor Nuclear Power Plant has been prepared from the latest available environmental and technical information collected from a number of sources. The typical plant chosen for characterization is a 1000-MWe nameplate rating with wet-natural-draft cooling towers and modern radwaste control and processing equipment.

The process, plant operating parameters, resources needed, and the environmental residuals and products associated with the power plant are presented in this section in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 70 percent, which was selected as representative of the average experience of all nuclear power plants during 1978-1979.[1]

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu (about 293 million kWh) of electrical energy produced. These figures are provided to allow comparison among energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section III. Thirteen environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions, and a bibliography of cited references. Specific environmental regulations are discussed in the individual sections.

Cost information, typical radioactive releases, and use of cooling ponds as an alternative cooling method are discussed in the appendixes. A glossary and list of acronyms and abbreviations are provided.

Reference

1. U.S. Nuclear Regulatory Commission, "Operating Status Report, Licensed Operating Reactors," NUREG 0020, Vol. 4, No. 2, February 1980, pp. 1-3.

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TABLE 1. SUMMARY SHEET

PRESSURIZED WATER REACTOR (PWR) NUCLEAR POWER PLANT

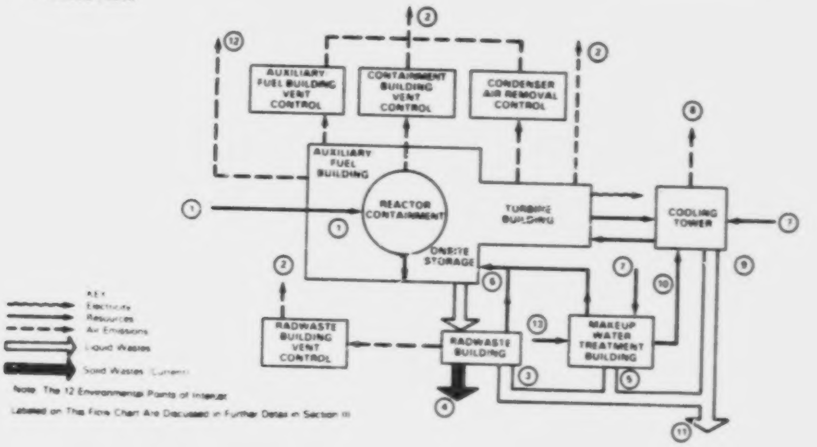
ENERGY SYSTEM DESCRIPTION

Pressurized Water Reactor Nuclear-Powered Electric Generating Plant Using 3.3% Enriched Uranium-235 Fuel; On-site Storage of Spent Reactor Fuel; Maximum Recycling of Liquid Radioactive Wastes; Filtration of Building Exhausts; On-site Water Treatment of River Supply Water; Natural Draft Wet Cooling Towers.

PLANT OPERATING PARAMETERS

Power Output to Grid:	1000 MWe
Annual Capacity Factor:	70% (assumed)
Overall Plant Efficiency:	33%
Annual Energy Production:	21 x 10^{12} Btu (6.13 x 10^6 MWh)
Plant Lifetime:	30-40 yr

PROCESS FLOW



⑫
②
②
AUXILIARY FUEL BUILDING VENT CONTROL
CONTAINMENT BUILDING VENT CONTROL
CONDENSER AIR REMOVAL CONTROL
⑧
AUXILIARY FUEL BUILDING
①
REACTOR CONTAINMENT
①
TURBINE BUILDING
COOLING TOWER
⑦
ONSITE STORAGE
②
⑥
⑦
⑩
⑨
KEY
Electricity
Resources
Air Emissions
Liquid Wastes
Solid Wastes (Current)
RADWASTE BUILDING VENT CONTROL
RADWASTE BUILDING
⑬
MAKEUP WATER TREATMENT BUILDING
③
⑤
④
⑪

Note: The 12 Environmental Points of Interest Labeled on This Flow Chart Are Discussed in Further Detail in Section III

RESOURCES USED

Code No.	Resource	Quantities Used — Annual Average* — English Units	Quantities Used — Annual Average* — Metric Units	Quantities Used — Per 10^{12} Btu Energy Produced	Remarks
	Construction Materials**				
	Concrete	250 x 10^3 yd^3	190 x 10^3 m^3	11.9 x 10^3 yd^3	
	Metal conduit	500 x 10^3 ft	150 x 10^3 m	24 x 10^3 ft	
	Cable tray	100 x 10^3 ft	30 x 10^3 m	4.8 x 10^3 ft	
	Large process pipe	160 x 10^3 ft	50 x 10^3 m	7.6 x 10^3 ft	
	Small pipe	200 x 10^3 ft	60 x 10^3 m	9.5 x 10^3 ft	
	Wire and cable	7 x 10^6 ft	2.1 x 10^6 m	0.3 x 10^6 ft	
	Water				
⑬	Power plant makeup water	5.1 x 10^9 gal	19.3 x 10^9 liters	0.24 x 10^9 gal	
	Fuel				
①	Uranium fuel – 3.3% U^{235} enriched	26.7 tons	24.3 tonnes	1.27 tons	33% of core annually
	Land				
④	Site land area**	1850 acres	750 ha	88.1 acres	
	Low-level radioactive waste disposal area	0.02 acre	0.008 ha	9 x 10^{-4} acre	

*Based on the assumed 70% capacity factor.
**One-time acquisition – not an annual requirement.

TABLE 1. (Continued)

PRESSURIZED WATER REACTOR (PWR) NUCLEAR POWER PLANT

RESOURCES USED (Continued)

Code No.	Resource	Quantities Used: Annual Average, English Units	Quantities Used: Annual Average, Metric Units	Quantities Used: Per 10^{12} Btu Energy Produced	Remarks
	Personnel				
	Permanent professional, trade, and administrative staff	230 man-yr		11 man-yr	
	Construction personnel				
	Average	2300 man-yr		110 man-yr	
	Peak	4300 man-yr		200 man-yr	

ENVIRONMENTAL RESIDUALS AND PRODUCTS

Code No.	Residual or Product	Quantities Released: Annual Levels*, English Units	Quantities Released: Annual Levels*, Metric Units	Quantities Released: Per 10^{12} Btu Energy Produced	Regulatory Compliance Levels
	Atmospheric Releases				
②	Major gaseous radwaste				**
	• Noble gases	1800 Ci	–	85.7 Ci	
	• Carbon-14	6.2 Ci	–	0.30 Ci	
	• Tritium	800 Ci	–	38.1 Ci	
⑫	Fossil fuel air emissions	53 tons	48 tonnes	2.5 tons	
⑧	Airborne water from cooling tower evaporation losses	3.8 x 10^9 gal	14.4 x 10^9 liters	0.18 x 10^9 gal	
	Liquids				
③	Liquid radwaste				**
	• Activated corrosion and fission products	0.12 Ci	NA	0.006 Ci	
	• Tritium	302 Ci	NA	14.4 Ci	
⑪	Nonradioactive liquid waste to river at point of discharge†	Metric units are universally used		Depends on flow, which varies widely	‡
	• Total suspended solids		12852 mg/liter		
	• Total dissolved solids		2863 mg/liter		
	• Iron		184 mg/liter		
	• Chloride		380 mg/liter		
	• Chromium		0.30 mg/liter		
	• Copper		0.73 mg/liter		
	• Zinc		0.84 mg/liter		
	Solids				
④	Low-level solid radwaste	5830 Ci 5900 ft^3	– 170 m^3	278 Ci 280 ft^3	
	Spent fuel	26.7 tons	24.3 tonnes	1.27 tons	

Symbols and abbreviations are defined in acronyms and abbreviations section.

*Based on the assumed 70% capacity factor.

**10CFR50 and 40CFR190 set forth individual isotope concentration limits.

†Concentrations — not annual quantities.

‡40CFR423 sets forth guidelines for allowable increase in river ambient concentrations.

OCCUPATIONAL SAFETY AND HEALTH

	Historical Exposure Data (1978 data): Annual	Historical Exposure Data (1978 data): Per 10^{12} Btu
Deaths	0.0	0.0
Injuries (number/total lost days)	0.51-3.0/14-91 days§	0.02-0.14/0.67-4.33§
Radiation exposure	428 man-rems per reactor 0.65 rem per man	20.4 man-rems per reactor 0.03 rem per man

§Average ± one standard deviation of historical data.

III. PLANT AND PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

For the convenience of the reader, the data presented in this report are normalized to 1000 MWe with an overall plant efficiency of 33 percent. Uranium dioxide fuel with approximately 3.3 percent uranium-235 enrichment is assumed. Resource utilization and environmental residual generation are based on a 70-percent annual capacity factor.

A block diagram of the major elements in the typical power plant is shown in Figure 1.[1] The reactor containment houses the primary plant, including the nuclear reactor and steam generators. The auxiliary/fuel building may be two separate buildings in some plant designs. In the SNUPPS design, they are combined. The auxiliary building houses the emergency cooling system support equipment, the chemical and volume control system (for reactor primary coolant specification and chemistry control), and major electrical switchgear. The fuel building houses the spent fuel pool where spent reactor fuel is cooled and stored. The turbine building contains portions of the secondary cooling and power conversion systems, including the turbine and electrical generator. The radwaste building houses the gaseous, liquid, and solid radwaste processing systems, and finally, the makeup water treatment building contains water purification equipment. Main condenser cooling is by natural-draft, hyperbolic cooling towers with makeup water supplied from local river sources.

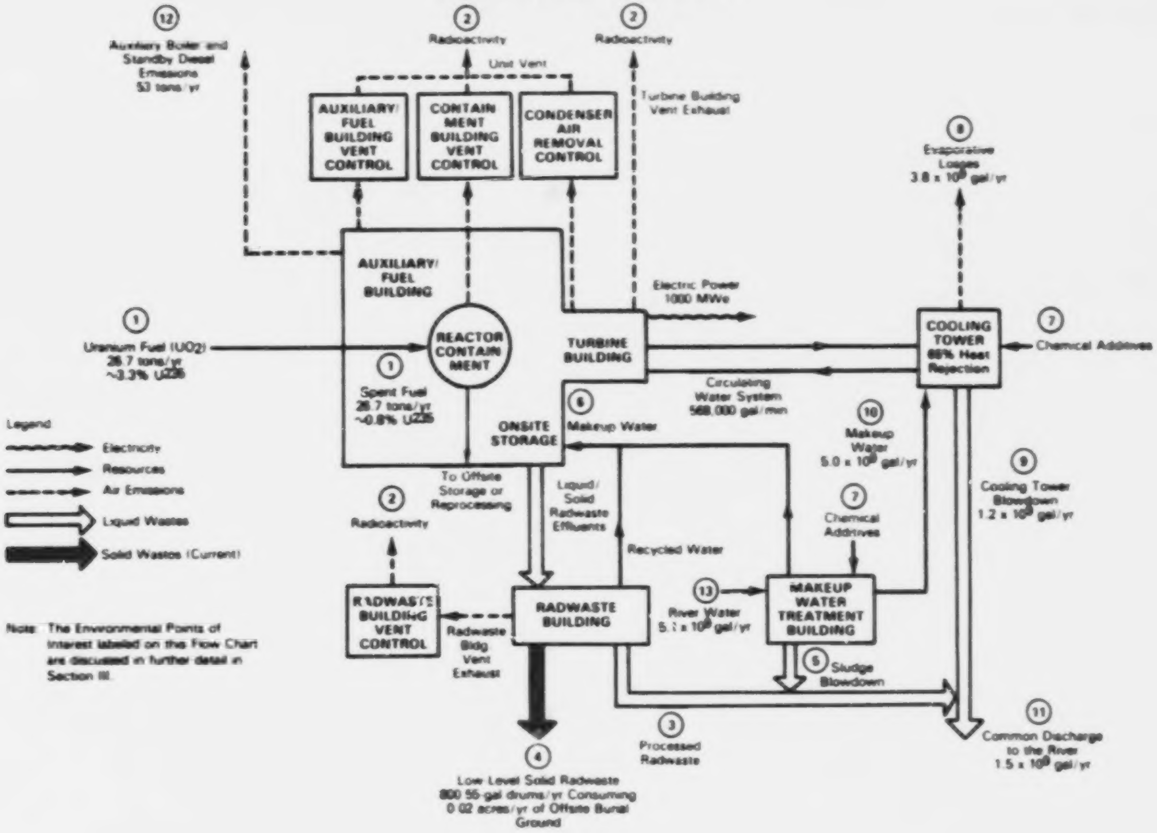
Environmental points of interest have been identified in Figure 1 and are characterized and discussed in the following sections. These points of interest identify the principal sources of radioactive and nonradioactive releases from the typical plant and the major uses of water, fuel, and land resources.

Cost information for the plant is given in Appendix A.

Reference

1. "Standardized Nuclear Unit Power Plant System (SNUPPS)," Final Safety Analysis Report, October 2, 1979, Chapter 1.

FIGURE 1.
PROCESS FLOW CHART WITH ENVIRONMENTAL POINTS OF INTEREST – PRESSURIZED WATER NUCLEAR POWER PLANT – 70% CAPACITY FACTOR


⑫
Auxiliary Boiler and Standby Diesel Emissions 53 tons/yr
②
Radioactivity
Unit Vent
②
Radioactivity
Turbine Building Vent Exhaust
AUXILIARY/ FUEL BUILDING VENT CONTROL
CONTAIN MENT BUILDING VENT CONTROL
CONDENSER AIR REMOVAL CONTROL
⑧
Evaporative Losses 3.8 x 10⁹ gal/yr
AUXILIARY/ FUEL BUILDING
Electric Power 1000 MWe
①
Uranium Fuel (UO2) 26.7 tons/yr ~3.3% U235
REACTOR CONTAIN MENT
①
Spent Fuel 26.7 tons/yr ~0.8% U235
TURBINE BUILDING
COOLING TOWER 68% Heat Rejection
⑦
Chemical Additives
Circulating Water System 568,000 gal/min
⑥
Makeup Water
ONSITE STORAGE
⑩
Makeup Water 5.0 x 10⁹ gal/yr
Legend
Electricity
Resources
Air Emissions
Liquid Wastes
Solid Wastes (Current)
To Offsite Storage or Reprocessing
②
Radioactivity
Liquid/ Solid Radwaste Effluents
Recycled Water
⑦
Chemical Additives
⑨
Cooling Tower Blowdown 1.2 x 10⁹ gal/yr
RADWASTE BUILDING VENT CONTROL
RADWASTE BUILDING
⑬
River Water 5.1 x 10⁹ gal/yr
MAKEUP WATER TREATMENT BUILDING
Radwaste Bldg Vent Exhaust
⑤
Sludge Blowdown
Note: The Environmental Points of Interest labeled on the Flow Chart are discussed in further detail in Section III.
③
Processed Radwaste
⑪
Common Discharge to the River 1.5 x 10⁹ gal/yr
④
Low Level Solid Radwaste 800 55-gal drums/yr Consuming 0.02 acres/yr of Offsite Burial Ground

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① Uranium Requirements and Spent Fuel Disposition

The amount of uranium dioxide (UO_2) fuel required to load the core of a 1000-MWe power plant is 80 tons. One-third of the core, 26.7 tons, will be replaced annually.

To determine how much UO_2 is required to operate a nuclear power plant, the following information is needed:

- Net electric power delivered to the transmission grid
- Percent enrichment of uranium-235 in the fuel
- Average thermal specific power in MWt/ton of the fuel

It is assumed that the typical plant is fueled with sintered UO_2 clad in zircaloy cladding, containing uranium enriched to approximately 3.3 percent uranium-235.[1] The corresponding thermal specific power for this fuel is 38 MWt/ton assuming a 33-percent conversion efficiency.[1]

In general,

$$\boxed{\text{Core load } UO_2 = \frac{(\text{net thermal power})}{(\text{thermal specific power})}}$$

For the typical plant,

$$\boxed{\text{Core load} = \frac{(1000 \text{ MWe}/0.33)}{38 \text{ MWt/ton}} = 80 \text{ tons } UO_2}$$

The reactor core is refueled by a program of partial batch replacement, in which one-third of the reactor core is replaced with new fuel each year; therefore, only 33 percent of the fuel (26.7 tons/yr) is expended annually.

The discharged fuel bundles are assumed to be stored onsite in the spent fuel cooling pool until a final national policy on fuel reprocessing and high-level radioactive waste storage is established. These pools provide cooling for the decay heat and shielding for plant operators. The capacity of the spent fuel cooling pool varies from a minimum of approximately 200 percent (one full core plus three annual batches) in older plants to 700 percent (one full core plus 18 annual batches) in newer plants with high density fuel racks. The larger capacity systems allow the utility to store up to 18 annual fuel batch replacements and still maintain the space for an emergency removal of the entire core. Utilities running out of storage space for spent fuel will have to obtain storage space elsewhere. The Department of Energy is sponsoring a program to develop away-from-reactor (AFR) storage sites that would accept spent fuel from these utilities. AFRs are expected to be in operation in the mid-1980s.[2]

The characteristics of the spent fuel as compared to the new fuel are shown in Table 2.[3] Initially, the activity immediately prior to shutdown is on the order of 10 billion curies. After about 150 days storage in the spent fuel cooling pool, many of the shorter-lived radionuclides have decayed to non-radioactive species, and the continuing decay is paced by the longer-lived radionuclides in the fuel. Longer storage of 30 to 60 additional days does not result in substantial further reduction in total radioactivity.[4] Consequently, the spent fuel could be loaded into heavily-shielded shipping casks for transfer to a fuel reprocessing plant after about a 150-day cooling period if reprocessing is performed.

However, due to the long half-lives of many of the remaining radionuclides and their biological hazards, the spent fuel, whether reprocessed or not, must be isolated from man's environment.

Table 2. Isotopic Transformation of New Fuel Into Spent Fuel

	New Fuel (Percent)	Spent Fuel After Operation (Percent, by Weight)
Uranium-235	3.3	0.80
Uranium-236	-	0.46
Uranium-238	96.7	94.30
Fission Products	-	3.50
Plutonium	-	0.89
Other Transuranics Isotopes*	-	0.05
Totals	100	100

* Transuranic isotopes are those having a greater atomic number than uranium, which are formed through the absorption of neutrons (without fissioning) in the uranium fuel (in particular uranium-238).

References

1. Teknekron Research, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, pp. 9-64.
2. Department of Energy, "Project Environmental Plan for Away From Reactor Storage Facilities," June 27, 1979.
3. Bernard L. Cohen, "The Disposal of Radioactive Wastes From Fission Products," Scientific American, June 1977.
4. WASH 1250, "The Safety of Nuclear Power Reactors," U.S. Atomic Energy Commission, July 1973, pp. 4-7.

② Gaseous Radioactive Effluents

Gaseous radioactive effluents from the typical plant will average 1800 Ci/yr for noble gases, 6.2 Ci/yr carbon-14, and 800 Ci/yr tritium, based on effluent calculations made using the Nuclear Regulatory Commission's GALE code with the SNUPPS standard power plant design.[1]

The PWR-GALE (Pressurized Water Reactor -- Gaseous and Liquid Effluents) Code is a generic computerized mathematical model used by NRC for calculating the releases of radioactive material in gaseous and liquid effluents from pressurized water reactors for purposes of licensing new reactors.[1]

In a pressurized water reactor power plant, the predominant gaseous source is from leakage of noncondensable gases into the primary coolant system through the condenser (air), or to a smaller degree from small fuel cladding defects (noble gases). The noncondensable gas, which is continuously stripped from the reactor coolant system by the gaseous radwaste system, is held up for 30 to 90 days to reduce the short-lived isotopes to negligible levels by radioactive decay. Alternate methods, e.g., cryogenic distillation, may be used at some plants to remove the noble gases. In the gaseous radwaste system as well as the major building ventilation systems and condenser offgas systems, the gases flow through particulate (HEPA) filters and charcoal adsorbers for radioactive iodine removal and discharge to the atmosphere through roof vents. Typically, the released radioisotopes dilute rapidly to concentrations far below the allowable levels by the time they reach the site boundary.[2]

The major sources of gaseous releases and the applicable control technology used are summarized in Table 3. In all cases, the effluents are monitored during discharge to ensure that the plant's technical specifications (based on the NRC design basis objectives given in 10 CFR 50, Appendix I) are not exceeded.

A detailed isotopic breakdown of the gaseous releases after processing through the systems listed in Table 3 is given in Table 4.

References

1. Nuclear Regulatory Commission, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents (GALE) from Pressurized Water Reactors," NUREG-0017, April 1976.
2. "Standardized Nuclear Unit Power Plant System (SNUPPS)," Final Safety Analysis Report, October 2, 1979, Chapter 9.

Table 3. Description of Major Sources of Gaseous Releases[2]

Release Point	Source of Activity	Factors That Mitigate Radioactive Releases	
		Holdup	Filter Combinations[a]
Containment building	1 percent/day and 0.001 percent/day of noble gas and iodine inventory in the reactor coolant, respectively, leakage into containment through valve stems and pump shaft seals	24 purges/ year	Internal: P-H-C-H[b] Exhuast: P-H-C-H
Auxiliary/fuel/radwaste buildings	Noble gas and volatile iodine from the spent fuel pool and leakage from valve stems and pump shaft seals[c]	No	Exhaust: P-H-C-H
Turbine building	1700 lb/hr of secondary steam leakage into turbine building through valve stems and pump shaft seals[d]	No	No
Condenser air removal system	Noble gas and volatile iodine in 100 lbs of primary coolant/day leaking into secondary system and stripped by air ejectors[c]	No	Exhaust: P-H-C-H
Gaseous radwaste system	Continuous stripping of gases from the reactor coolant volume control tank during power operation and degassing of reactor coolant during 2 cold shutdowns/year	90 days	Exhaust: P-H-C-H

---

[a] P --prefilter or roughing filter; H -- HEPA filter; C -- charcoal adsorber efficiencies of 99 percent for particulates and 70 percent for radioiodines assumed in activity release calculations; however, expected efficiencies for iodine removal are 99 percent for elemental iodine and 95 percent for organic iodine at 70-percent relative humidity.

[b] No credit has been taken for the internal recirculation cleanup.

[c] 5 percent of the iodine in the primary coolant is assumed to be in the volatile form.

[d] Secondary steam activities are based on 100 lb/day primary-secondary leakage and a partition factor of 0.01 between liquid and vapor phases in the steam generator for iodines.

Table 4. Annual Gaseous Radioactive Effluents (Ci)

		Unit Vent				Ground Level				
Nuclide	Half-Life Days	Fuel/Aux. Building[a]	Air Ejector	Containment[b] Building	Total	Gas Radwaste System	Radwaste Building	Turbine Building	Total	PLANT TOTAL
Noble Gases										
Kr-83m	7.75-2[c]	0	0	0	0	0	0	0	0	0
Kr-85m	1.83-1	0.780	0.780	1.56	3.12	0	0.780	0	0.780	3.90
Kr-85	3.93+3	0	0	4.68	4.68	200	0	0	200	205
Kr-87	5.42-2	0.390	0	0	0.390	0	0.39	0	0.39	0.78
Kr-88	1.17-2	1.56	2.34	1.56	5.46	0	1.56	0	1.56	7.02
Kr-89	2.20-3	0	0	0	0	0	0	0	0	0
Xe-131m	1.19+1	0	0	7.80	7.80	2.34	0	0	2.34	10.1
Xe-133m	2.30+0	0.780	0.780	14.8	16.4	0	0.78	0	0.78	17.2
Xe-133	5.27+0	47.9	53.8	1400	1500	0.78	42.9	0	43.7	1544
Xe-135m	7.75-3	0	0	0	0	0	0	0	0	0
Xe-135	1.53-1	2.73	4.12	7.80	14.7	0	2.73	0	2.73	17.4
Xe-137	2.60-3	0	0	0	0	0	0	0	0	0
Xe-138	9.72-3	0.39	0	0	0.39	0	0.39	0	0.39	0.78
Ar-41	7.62-2	0	0	19.5	19.5	0	0	0	0	19.5
										1800
Iodine										
I-131	8.05+0	5.2-3	6.5-3	2.8-2	4.0-2	0	5.2-3	1.9-4	5.4-3	0.05
I-133	8.75-1	7.5-3	9.4-3	6.8-3	2.4-2	0	7.5-3	2.6-4	7.8-3	0.03
Tritium										0.08
H-3	4.48+3	d	0	c	800	0	0	0	0	800
Carbon-14										
C-14	2.09+6	0	0	0.78	0.78	5.46	0	0	5.46	6.2
Particulates										
Mn-54	3.30+2	4.0-5	0	1.7-4	2.1-4	4.0-5	8.0-5	0	1.2-4	3.3-4
Fe-59	4.50+1	2.0-5	0	6.0-5	8.0-5	1.0-5	2.0-5	0	3.0-5	1.1-4
Co-58	7.13+1	2.3-4	0	5.9-4	8.2-4	1.2-4	2.3-4	0	2.5-4	1.2-3
Co-60	1.92+3	1.1-4	0	2.7-4	3.8-4	6.0-5	1.1-4	0	1.7-4	5.5-4
Sr-89	5.20+1	1.0-5	0	1.0-5	2.0-5	0	1.0-5	0	1.0-5	3.0-5
Sr-90	1.02+5	0	0	0	0	0	0	0	0	0
Cs-134	7.49+2	4.0-5	0	1.7-4	2.1-4	4.0-5	7.0-5	0	1.1-4	3.2-4
Cs-137	1.10+4	1.2-4	0	3.0-4	4.2-4	6.0-5	1.2-4	0	1.8-4	6.0-4
										0.003

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[a] Auxiliary building release outputs by GALE Code are evenly split between fuel/aux. building and radwaste building.

[b] 20 intermittent purges at power +4 shutdown purges are assumed for the containment building.

[c] This notation represents 7.75 x 10^{-2}, etc.

[d] GALE Code calculates only total tritium releases.

NR -- Not Recorded

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③ Liquid Radioactive Effluents

The liquid radioactive effluents from the typical plant will average 0.12 Ci/yr from activated corrosion and fission products and 302 Ci/yr tritium.

Effluent calculations were made using the Nuclear Regulatory Commission's (NRC) PWR-GALE Code discussed in item ② . The calculations are based on data generated from operating reactors, field and laboratory tests, and plant-specific design considerations incorporated to reduce the quantity of radioactive materials that may be released to the environment.

The average quantity of radioactive material released to the environment from a nuclear power reactor during normal operation is called the "source term," as it is the source or initial number used in calculating the environmental impact of radioactive releases. The calculations performed by the PWR-GALE Code are based on (1) standardized primary and secondary cooling system activities derived from American Nuclear Society (ANS-237) recommendations, as modified by the NRC, (2) the release and transport mechanisms that result in the appearance of radioactive material in liquid and gaseous waste streams, and (3) plant-specific design features used to reduce the quantities of radioactive materials ultimately released to the environment.

A detailed isotopic breakdown and the source of the calculated releases from the SNUPPS plant using the GALE Code are provided in Table 5. The following assumptions are built into the calculations in that table:

1. 0.12 percent fuel defects
2. 100 lb/day primary coolant system to secondary coolant system leakage through the steam generator
3. Basis for radioactive sources obtained from NRC Regulatory Guide 1.112
4. Steam generator moisture carryover is 0.25 percent
5. 1000-MWe plant operating at 70-percent capacity factor

The typical plant is designed to minimize liquid effluent releases and will process and recycle the majority of the liquid wastes. However, a portion of the following sources are assumed to be discharged to the river after processing and are factored into the results of Table 5:

Table 5. Calculated Annual Liquid Releases by Source (mCi)[2]

Nuclide	Half-life (Days)	Boron Recovery System	Process Liquid Wastes	Secondary Liquid Waste System	Total Liquid Waste*	Adjusted Total**	Detergent Wastes	Total
Corrosion & activation products								
Cr-51	2.78+01	0.01	0	0	0.01	0.14	0	0.14
Mn-54	3.30+02	0	0	0	0	0.03	0.07	0.10
Fe-55	9.50+02	0.01	0	0	0.01	0.15	0	0.15
Fe-59	4.50+01	0.01	0	0	0.01	0.08	0	0.08
Co-58	7.13+01	0.07	0.01	0	0.08	1.34	0.29	1.63
Co-60	1.92+03	0.01	0	0	0.01	0.18	0.64	0.82
Fission products								
Br-83	1.00-01	0	0	0	0	0.01	0	0.01
Rb-86	1.87+05	0	0	0	0	0.05	0	0.05
Sr-89	5.20+01	0	0	0	0	0.03	0	0.03
Mo-99	2.79+00	0.05	0.03	0.01	0.09	1.43	0	1.43
Tc-99m	2.50-01	0.04	0.03	0.01	0.08	1.36	0	1.36
Te-127m	1.09+02	0	0	0	0	0.02	0	0.02
Te-127	3.92-01	0	0	0	0	0.02	0	0.02
Te-129m	3.40+01	0.01	0	0	0.01	0.10	0	0.10
Te-129	4.79-02	0	0	0	0	0.07	0	0.07
I-130	5.17-01	0	0	0	0	0.04	0	0.04
Te-131m	1.25+00	0	0	0	0	0.01	0	0.01
I-131	8.05+00	0.05	1.69	0.29	2.03	31.69	0.01	31.70
Te-132	3.25+00	0.02	0.01	0	0.03	0.52	0	0.52
I-132	9.58-02	0.02	0.02	0.02	0.06	0.99	0.04	1.03
I-133	8.75-01	0	0.43	0.33	0.76	11.87	0	11.87
Cs-134	7.49+02	1.53	0.02	0.01	1.56	24.35	0.96	25.31
I-135	2.79-01	0	0.04	0.10	0.14	2.16	0	2.16
Cs-136	1.30+01	0.43	0.01	0	0.44	7.00	0	7.00
Cs-137	1.10+04	1.12	0.01	0	1.13	17.72	1.77	19.49
Ba-137m	1.77-03	1.05	0.01	0	1.06	16.57	0	16.57
Ba-140	1.28+01	0	0	0	0	0.01	0	0.01
La-140	1.67+00	0	0	0	0	0.01	0	0.01
All Others		0	0	0	0	0.05	0	0.05
Total (Except tritium)		4.43	2.31	0.77	7.51	118.00	3.78	121.78
Tritium release		302 Ci per year						

* Nondetergent

** Adjustment is to allow margin for operational variances, consistent with NRC practices.

NR — Not Recorded

- Processed Liquid Radwastes
  - Chemically clean radwaste from the reactor coolant system
  - Chemically dirty radwastes from floor drains, health physics laboratory, equipment decontamination, and tank leakoffs
  - Accidental spills and leaks
  - Boron recycle system
- Secondary Coolant Liquid Wastes
  - Condensate demineralizer regeneration (not used in some plants)
  - Turbine building floor drains
- Laundry Detergent Wastes

It is assumed that all of the steam generator blowdown is processed and recycled under normal plant operating conditions.[2]

Appendix B (to be added later) will compare major differences in PWR systems, including liquid effluents.

The Code of Federal Regulations, Title 40, Part 190 (40 CFR 190), sets forth standards on radiation exposure to individual members of the public due to activities in the uranium fuel cycle, including light water reactors.[3] The Nuclear Regulatory Commission regulates releases of radioactive effluents according to 40 CFR 190 and also according to NRC's Appendix I to 10 CFR Part 50, by incorporating into the technical specifications, which are part of the Plant Operating License, limits on the quantities of radionuclides that can be released.

References

1. Nuclear Regulatory Commission, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents (GALE) from Pressurized Water Reactors," NUREG-0017, April 1976.
2. "Standardized Nuclear Power Plant System (SNUPPS)," Final Safety Analysis Report, October 2, 1979, Tables 11.1-2 and 11.1A-2.
3. Code of Federal Regulations, Title 40, Part 190, "Standards for Protection Against Radiation."

④ Low-Level Solid Radioactive Wastes

Low-level solid radioactive wastes from the typical plant will average 5830 Ci/yr and will require 0.02 acre of offsite burial ground annually.[1,2]

Concentrated waste solutions from the boron recycle system (some boron wastes are nonrecyclable), liquid radwaste from the evaporators and the laundry, spent resins from the demineralizers, spent charcoal, and laboratory and chemical wastes are solidified in the solid radwaste system and shipped offsite in 55-gallon drums for burial. In addition, dry wastes, i.e., paper and clothing are compacted and shipped in a similiar manner. Refer to Table 6 for a breakdown of the estimated annual wastes. The quantities of waste in Table 6 will not vary significantly with plant size. Packaging and shipment of the solid wastes are performed in accordance with the Code of Federal Regulations 10 CFR 71 and 49 CFR 179, and applicable state and local regulations.[3,4]

Low-level solid nuclear wastes are buried in federally licensed burial grounds. The average annual burial ground usage is given by

$$\text{Burial ground usage, acres/yr} = (\text{number of drums shipped offsite/yr})/(\text{drums/acre})$$

With an average burial ground density[2] of 19,240 m^3/ha (38,931 drums/acre), the requirement for each power plant becomes

$$\text{Burial ground usage, acres/yr} = (800\ \text{drums/yr})/(38{,}931\ \text{drums/acre})$$
$$= 0.02\ \text{acre/yr}$$

References

1. "Standardized Nuclear Unit Power Plant System (SNUPPS)," Final Safety Analysis Report, October 2, 1979, Chapter 11.
2. U.S. Department of Energy, Office of Nuclear Waste Management, "Spent Fuel and Waste Inventories and Projections," ORO-778, August 1980, pp. 40 and 53.
3. Code of Federal Regulations, Title 10, Part 71, "Packaging of Radioactive Material for Transport and Transportation of Radioactive Material Under Certain Conditions."
4. Code of Federal Regulations, Title 49, Part 179, "Specification for Tank Cars."

Table 6. Estimated Annual Activities and Quantities of Solid Radwaste

Source	Total Activity (Curies)	Shipping Volume[a]
Spent resins and filter cartridges	5800	170 drums[b,c]
Liquid waste processing system evaporator bottoms	29	110
Processed laundry and personnel decontamination wastes	.064	55
Miscellaneous chemical wastes	.039	60
Dry and compacted wastes	5	450
Total	5830	≈800 drums

[a] Based on the actual SNUPPS design, which uses state-of-the-art techniques to minimize waste volume; other plants may have greater volume and lower radioactivity. Reference 1 cites 609 m^3 (about 3000 drums) as the annual volume from a typical existing PWR.

[b] Drums = 55 gallons.

[c] Larger containers are also used, but to avoid complexity, the common 55-gallon drum is used as a unit size.

⑤ Makeup Water Treatment Blowdown

Blowdown from the makeup water treatment plant is discharged to the river to remove accumulated sludge from the clarifiers.

Makeup water from the river is processed in clarifiers and softeners to remove approximately 95 percent of the suspended solids prior to plant use.[1] The suspended solids are coagulated in rapid mix units by the addition of 0.5 mg/l of polyelectrolytes to the river water. The removed solids are discharged to the river along with the other nonradioactive effluents. This sludge blowdown accounts for 190,000 gal/day of the 6 x 10^6 gal/day total plant effluent[1] (see item ⑪).

In some areas, the river makeup water may contain too high a concentration of suspended solids so that after removal by the makeup water treatment system clarifiers, the sludge must be handled as solid waste and not be dumped back into the river as assumed in the typical plant. At these sites, the makeup water treatment blowdown is sent to a basin to allow the majority of the suspended solids to settle to the bottom. Overflow from the settling basins will contain a lower concentration of total suspended solids and will be directed back to the river. The settled sludge would be dredged periodically and disposed of at an approved burial ground.[2]

References

1. Union Electric Company, Callaway Plant Environmental Report, Operating License Stage, 1979, p. 3.6-1.
2. River Bend Nuclear Station Environmental Report, Construction Permit Stage, p. 3.6-3.

⑥ Miscellaneous Plant Makeup Water

The makeup water required for miscellaneous plant services is 81.8 x 10^6 gal/yr.

The majority of this water (79.2 x 10^6 gal/yr) is demineralized to a high purity level and is used to compensate for water losses from primary to secondary systems, reactor coolant letdown, etc. The remaining makeup water is potable water for such in-plant uses as laundries, showers, sanitary facilities, and drinking.

The daily requirements for makeup water at 100-percent capacity is 320,000 gal/day[1], which is made up of 10,000 gal/day of potable water and 310,000 gal/day of demineralized plant water. Therefore, on an annual basis,

$$\boxed{\begin{aligned}\text{Annual plant makeup water} &= (320{,}000\ \text{gal/day})(365\ \text{days/yr})(0.7\ \text{capacity factor})\\ &= 81.8 \times 10^6\ \text{gal/yr}\end{aligned}}$$

The amount of water required for miscellaneous plant makeup will not vary significantly with plant size.

Reference

1. Union Electric Company, Callaway Environmental Report, Operating License Stage, 1979, p. 3.3-1.

⑦ Chemical Usage

Water from the river undergoes various treatments, including clarification, demineralization, stabilization (scaling treatment), pH control (acid addition), and biocide treatment (chlorination) prior to being used as makeup for different plant processes.

Large amounts of chemicals are added to the makeup water. Table 7 summarizes the types of chemicals added at a typical plant, their purpose, frequency of use, and quantity used. These quantities will vary greatly from plant to plant depending on the local water quality and on the amount of makeup water used.

Chemicals are also used in the power plant for primary and secondary system water chemistry control. Lithium hydroxide or hydrazine is used for pH control in the primary system; hydrazine, phosphates, or ammonia is used for pH control in the secondary system; boron is added to the primary system for reactivity control (control of neutrons); and hydrogen is added to the primary system to scavenge oxygen for corrosion control.[1]

Reference

1. Union Electric Company, Callaway Environmental Report, Operating License Stage, 1979, Section 3.6.

Table 7. Chemical Usage in Makeup Water Systems[1]

			Quantity Used		
			Average		Maximum
Chemical	Use	Frequency of Use	lb/day*	lb/yr**	lb/day
Polyelectrolyte (liquid cationic)	River water clarification	Continuous	100	25,500	1,175
Sodium Hydroxide	Demineralizer regeneration	Once per train per day (2 hours/day)	2,450	626,000	3,700
Sulfuric Acid	Demineralizer regeneration	Once per train per day (2 hours/day)	2,100	536,600	3,100
Sulfuric Acid	Recirculating cooling water pH control	Continuous	12,600	3,219,300	15,500
Rock Salt	Produce sodium hypochlorite (see below)	As needed (hypochlorite used on an intermittent basis)	4,200	1,073,100	8,750
Sodium Hypochlorite	Biocide treatment of recirculating cooling water	Approximately 2 hours per day per cooling tower	1,200	306,600	2,500
Dispersant (organic phosphonate)	Scale inhibition in cooling water systems	Continuous	935	238,900	1,150

* 100% capacity

** 70% capacity

⑧ Evaporative Losses From Wet Cooling Towers

Evaporative losses from the cooling towers into the atmosphere will be approximately 3.8 x 10^9 gal/yr for a typical 1000-MWe power plant operating at full load.

The evaporation loss in the cooling tower is a fraction of the percentage of the net heat released to the circulating water system and the heat of vaporization of the water (which is a function of relative humidity and wet bulb temperature). In general,[1]

$$W_{EVAP}, \text{ gal/day} = \frac{2880 \text{ (percent gross heat rejected to tower)}(\dot{Q})(P)}{\text{(water heat of vaporization, Btu/lb)}}$$

Where

$\dot{Q}$ = Net station heat rate = 10,342 Btu/kWh at 33% efficiency
P = Net electrical power = 1000 MWe

If 65 percent of the gross heat released from the nuclear reactor is rejected to the circulating water (2 percent is lost elsewhere in the plant) and the water heat of vaporization is assumed to be 1300 Btu/lb,* then for the typical plant the water requirements are as follows:

$$W_{EVAP} = \frac{2{,}880\ (0.65)(10{,}342 \text{ Btu/kWh})(1000 \text{ MWe})}{(1300 \text{ Btu/lb})}$$
$$= 14.9 \times 10^6 \text{ gal/day}$$

On an annual basis,

$$W_{EVAP} = (14.9 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.7 \text{ capacity factor})$$
$$= 3.8 \times 10^9 \text{ gal/yr}$$

---

* This figure is based on actual operating data from Reference 1 and is greater than the typical textbook value of 1050 Btu/lb.

These cooling tower losses may interact with the local climate and cause visibility impairment, fogging, or icing conditions. There are no existing regulations limiting cooling tower losses to the atmosphere. Because state-of-the-art cooling tower practice employs high-efficiency drift eliminators, drift losses will be negligible.

For illustrative purposes, the chemical composition, in mg/l, of the dissolved solids in the cooling tower basin is as follows for this model plant using one set of specific data:[3]

Sulfate	2012	Cadmium	0.088
Sodium	404	Chromium	0.28
Phosphonates	20	Copper	0.72
Dissolved Solids	2592	Nickel	0.02
Total Alkalinity	1276	Lead	1.12
Total Hardness	1400	Manganese	2.0
Suspended Solids	60	Mercury	4.0
Nitrate	26	Zinc	0.84
Iron	184	Hexane Solubles	106.8
Chloride	360		
Silica	160		

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
2. Union Electric Company, Callaway Plant Environmental Report, Operating License Stage, 1979, Chapter 3.
3. Callaway Environmental Report, op.cit., Chapter 5.

⑨ Cooling Tower Blowdown

Cooling tower blowdown is equivalent to 20 to 30 percent of the evaporation losses.[1] For a typical plant, blowdown will be 1.2 x 10^9 gal/yr and will be discharged to the river.

Because the water makeup to the cooling system contains dissolved or suspended solids that are not removed in the evaporation process, it is necessary to discharge a portion of the water called blowdown, to keep the dissolved solids from building up to a high concentration in the water circulation system. The blowdown rate, which depends on the salt concentration in the makeup water and the tolerable salt concentration in the circulating system and in the blowdown, will typically range from 20 to 30 percent of the evaporation rate.[1,2]

Whenever necessary, blowdown can be treated prior to discharge to a receiving water body. In certain cases, the cooling tower blowdown can be discharged into a closed reservoir or lagoon where solids are precipitated and then removed prior to discharge of the water to the river. This is not assumed in the typical plant.

In addition to the concentrated dissolved solids, the drift and blowdown water from evaporative cooling systems will contain chemicals added to the circulating water to prevent scale, to control corrosion, and to prevent microbiological growth. Sulfuric acid is usually added to lower the pH of the water, reducing the deposition of dissolved solids as scale on the condenser heat transfer surfaces. Corrosion inhibitors generally are a combination of cathodic and anodic inhibitors. The chromate-based inhibitors have been the most widely used. Where it is has been necessary to discontinue the use of environmentally hazardous chromates, blends of zinc sulfate and lignosulfonates are used. Other chemical combinations for inhibiting corrosion are chromates-zinc, chromates-hexametaphosphates, chromates-organics, chromates-hexametaphosphates-zinc, chromate-zinc-organic, organic-zinc, nitrites, sodium silicates, sodium silicated with dispersives and antinucleating agents, and organic phosphonates. Biocides used to kill microorganisms in the cooling tower and the circulating water system consist of compounds of chlorine, bromine, or acrolein.[3] As indicated in Table 7 in item ⑦, sulfuric acid for pH control, organic phosphonates for corrosion control, and sodium hypochlorite for biocide control are assumed in the typical plant. Refer to item ⑪ for the predicted concentrations of various chemicals discharged to the river for the typical plant.

In general,

$$W_{BLOWDOWN} = 0.3\ W_{EVAP}$$

For the typical plant,

$$\begin{aligned} W_{BLOWDOWN} &= 0.3\ (14.9 \times 10^6 \text{ gal/day}) \\ &\approx 4.5 \times 10^6 \text{ gal/day} \end{aligned}$$

On an annual basis,

$$\begin{aligned} W_{BLOWDOWN} &= (4.5 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.7 \text{ capacity factor}) \\ &= 1.2 \times 10^9 \text{ gal/yr} \end{aligned}$$

$$\begin{aligned} W_{TOW} &= W_{EVAP} + W_{BLOWDOWN} \\ &= (14.9 \times 10^6 \text{ gal/day}) + (4.5 \times 10^6 \text{ gal/day}) \\ &= 19.4 \times 10^6 \text{ gal/day} \end{aligned}$$

The number of "cycles" to which the circulating water system can be concentrated is measured by the ratio of the makeup water to the tower loss rates, as follows:[4]

$$N = \frac{W_{TOW}}{W_{BLOWDOWN}}$$

For the typical plant,

$$\begin{aligned} N &= \frac{19.4 \times 10^6 \text{ gal/day}}{4.5 \times 10^6 \text{ gal/day}} \\ &= 4.3 \text{ cycles} \end{aligned}$$

References

1. Union Electric Company, Callaway Environmental Report, Operating License Stage, 1979, Table 3.4-1.
2. Geoffrey G. Eichholz, Environmental Aspects of Nuclear Power, Ann Arbor Science Publications, Inc., 1976, p. 247.
3. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
4. Teknekron Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 142.

⑩ Cooling Tower Makeup

Approximately 5.0 x 10^9 gal/yr are needed to make up cooling tower losses due to evaporation and blowdown for a typical plant.

From item ⑨, W_{TOW} is 19.4 x 10^6 gal/day. On an annual basis, this makeup requirement is

$$W_{TOW} = (19.4 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.7 \text{ capacity factor})$$
$$= 5.0 \times 10^9 \text{ gal/yr}$$

The above analysis is for a wet cooling system only. When water is expensive (greater than about \$0.80/10^3 gallons), however, or of limited availability, combined wet and dry cooling systems or cooling ponds might be used. For wet/dry systems, the average annual water consumption is between 10 and 25 percent of the all-wet system used in this ECIR.[1] Refer to Appendix C for a discussion on cooling ponds as a heat sink.

Reference

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.

⑪ Common Waste Discharge to the River (Nonradioactive)

Various chemical and biocide wastes will be discharged to the river and will be subject to EPA and state guidelines.

Sources of chemical and biocide waste discharges from the typical plant are summarized below:

1. Water treatment plant sludge (where permitted, see item ⑤)
2. Water filter backwash
3. Demineralizer regenerant wastes
4. Oily wastewater separator effluent
5. Softener regenerant
6. Building floor drains
7. Cooling tower blowdown

All wastewaters are eventually discharged to the river through the plant discharge line. Cooling tower blowdown, water treatment sludge, oily wastewater separator effluent, and softener regenerant are discharged directly to the river or are pretreated, depending on applicable regulations. Demineralizer regenerant wastes and floor drainage are pumped to a neutralization tank for pH monitoring and adjustment. The neutralized waste is combined with filter backwash and sent to an equalization basin. Overflow from the basin enters the plant discharge line. Building floor drains are sent through an oil separator and neutralization pit before discharge to the river. Some of these wastewaters are potentially radioactive and are monitored prior to direct discharge into local waters and are treated in the liquid radwaste system as necessary.

Concentrations of various chemicals in the plant effluent are summarized in Table 8. Plant effluent concentrations are based on maximum chemical treatment rates and maximum plant water discharge rates (6×10^6 gal/day).[1] These concentrations will not vary significantly with plant size. The effects of chemical discharges on the ambient concentration levels in the river are subject to the Environmental Protection Agency Guidelines set forth in 40 CFR 423 for new source power generating plants and the state permits based on National Pollutant Discharge Elimination System (NPDES) procedures and guidelines.[2] For a discussion on radioactive wastes discharged to the river, see item ③.

References

1. Union Electric Company, Callaway Environmental Report, Operating License Stage, 1979, p. 3.6-3.
2. Code of Federal Regulations, Title 40, Part 423, "Effluent Standards and Guidelines for Steam Electric Generating Plants."

Table 8. Concentrations of Various Chemicals in the Plant Effluent at the Discharge Point Before Mixing in the River[1]

Parameter	Plant Effluent Concentration
Total dissolved solids, mg/l	2,863
Total alkalinity ($CaCO_3$, mg/l)	1,182
Total hardness ($CaCO_3$, mg/l)	1,400
Turbidity, JTU	9,600
Suspended solids, mg/l	12,852
Specific conductance, mhos/cm	3,600
Nitrate, mg/l	25.8
Total iron, mg/l	184
Sulfate, mg/l	2,063
Chloride, mg/l	360
Silica, mg/l	160
Cadmium, mg/l	0.088
Chromium, mg/l	0.28
Sodium, mg/l	426
Copper, mg/l	0.73
Lead, mg/l	1.12
Manganese, mg/l	2.0
Mercury, mg/l	4.0
Zinc, mg/l	0.84
Hexane solubles, mg/l	106.8
Arsenic, mg/l	0.056

⑫ Miscellaneous Fossil Fuel Combustion Products

Small amounts of combustion products are generated through the periodic operation of the auxiliary boiler and the standby diesel generators.

The two standby diesel generators (6190 KWe each) are operated during the abnormal condition when offsite electrical power is lost; otherwise, they are operated only while testing for approximately 2 hours per month using No. 2 diesel fuel oil.[1] No treatment is planned for the effluents. The auxiliary boiler (123 x 10^6 Btu/hr) is operated during plant startup and other conditions when the plant's main steam is unavailable.[1] It is assumed that the auxiliary boiler is operated 2 months out of the year during refueling and other outages. There are no applicable Federal emission regulations for combustion products emitted from boilers with capacities under 250 x 10^6 Btu/hr.[1] See Table 9 for the estimated annual emission rate of the major pollutants from the diesel generators and auxiliary boiler.

Table 9. Estimated Quantities of Fossil Fuel Emissions

Emission Products	Auxiliary Boiler (123×10^6 Btu/hr) (at 50-percent rated capacity)	Estimated[1] Annual Release (tons)	Diesel Generator (6190 kWe) (at rated capacity) (lb/hr)	Estimated Annual Release[2] (tons)	Total Annual Releases (tons)
Particulates	6.2 lb/hr	4.5	11.4	0.8	5.3
Sulfur oxides	19.1 lb/hr	13.8	19.1	1.4	15.2
Nitrogen oxides	18.5 lb/hr	13.8	214	15.4	29.2
Carbon monoxide	100 ppm	Insignificant	39.8	2.9	2.9
Hydrocarbons	50 ppm	Insignificant	7.6	0.5	0.5
				Total	≈53

[1] It is assumed that the auxiliary boiler is operated for 2 months a year at 50-percent capacity.

[2] It is assumed that the two diesel generators are operated at rated capacity 2 hours/month for testing and 48 hours during loss of offsite power.

Reference

1. Kansas Gas and Electric, Wolf Creek Generating Station Environmental Report, Operating License Stage, p. 3.7-1.

⑬ Total Plant Makeup Water

A total of 4.8×10^9 gal/yr is necessary to provide makeup water for the cooling towers and miscellaneous plant services.

Total plant makeup water demands are broken down as follows:[1]

Source	Item	Quantity (gal/day)
Cooling Tower Makeup	⑩	19.4×10^6
Potable Water	⑥	0.01×10^6
Demineralized Plant Water	⑥	0.31×10^6
Makeup Water Treatment Building Blowdown	⑤	0.19×10^6
Total	⑬	19.9×10^6
		or 5.1×10^9 gal/yr at 70-percent capacity factor

Reference

1. Union Electric Company, Callaway Plant Environmental Report, Operating License Stage, Figure 2.3-1.

IV. PHYSICAL REQUIREMENTS

Land, water, and construction material resources are required for a nuclear power plant. Water requirements are discussed in item ⑬. Land and construction material requirements are discussed below.

The typical single unit nuclear power plant site will occupy 1850 acres of land. The sizes of power plant sites vary over a considerable range and depend on a number of factors, e.g., plant design features, local meteorology, local ecology, area population, cost of land, and proximity to industry and transportation corridors. In general, the limiting factor is the radiological dose calculation under normal and accident conditions that are greatly affected by population distribution and local meteorology.

Title 10 of the Code of Federal Regulations Part 100 requires the utility to have control of access to an exclusion area around the reactor containment building.[1] The size of the exclusion area is based on not exceeding a specified dose to any member of the public at the exclusion area boundary under design basis accident conditions. Generally, the utility will own all the land inside the exclusion area. A study of seven different single unit nuclear power plants (1000 MWe or greater) showed that the average exclusion area for a single-unit site is 725 acres with a standard deviation of 100 acres.[2]

In general, the actual plant site will be larger than the required exclusion area. A study of seven nuclear power plants showed that the site areas averaged 1850 acres with a standard deviation of 1400 acres.[2] This large variance in site area is not necessarily attributed to licensing requirements but may be a result of utility preference in buying the land for recreational purposes, expansion, etc.

Land requirements for low-level radioactive waste disposal are discussed in item ④. The materials required to construct a plant will depend on the individual design. The quantities shown below are representative:[3]

Concrete	250×10^3 yd^3
Metal conduit	500×10^3 ft
Cable tray	100×10^3 ft
Large process pipe	160×10^3 ft
Small pipe	200×10^3 ft
Wire and cable	7×10^6 ft

References

1. Code of Federal Regulations, Title 10, Part 100, "Reactor Site Criteria."
2. Oak Ridge National Laboratory, "Design Data and Safety Features of Commercial Nuclear Power Plants," ORNL-NSIC-55, March 1975.
3. Personal communication, Robert Renuart, Bechtel Power Corporation, September 1980.

V. OCCUPATIONAL HEALTH AND SAFETY

There are primarily two categories of risk to the worker at a nuclear power plant: the day-to-day risks of industrial accidents such as electrocution, steam burns, falls, etc., and the latent risk of the still uncertain effects from exposure to chemical compounds and low-level radiation. A third risk, which is considered of sufficiently low probability that it is not discussed here, is the danger of acute illness from radiation exposure during a major nuclear reactor accident.

Industrial Accidents

The Occupational Safety and Health Act of 1970 requires that all industries maintain records on injuries and illnesses, not necessarily disabling, that result in actual lost work time.[1] Hoy and O'Donnel have compiled detailed statistics on occupational injuries and illnesses during light-water reactor construction, testing, operation, and maintenance from the Tennessee Valley Authority (TVA) Annual Reports during 1975 to 1979. They show that an average of 0.77 injuries and 23 lost days occur every 100 man-years of working time. Table 10 lists the incidence rates calculated from the TVA data. TVA has operated a three-unit nuclear power plant since the early 1970s and has 1 reactor in the early stages of plant start up and 13 more under construction. Although the TVA data were accumulated in BWR plants, the industrial accident statistics are assumed to be comparable to those of PWR plants. TVA radiation exposure data are of course different and were not used.

Bertolett and Fox obtained operational and maintenance injury data during 1969 to 1972 from five nuclear power electric utilities.[2] The data were gathered under the older American National Standard Institute (ANSI) system, which is based on recording lost time for disability injuries only. These data have been widely accepted for use in risk assessment. A comparison of the TVA and Bertolett and Fox studies is presented in Table 10. The two studies show fairly consistent results even though the statistical base is slightly different (OSHA versus ANSI).

Exposure to Low-Level Radiation

Radiation exposures to operating personnel are maintained as low as reasonably achievable within the limits of 10 CFR 20, which states that a worker may not receive more than 5 rem per calendar year not to exceed 3 rem in any one quarter to the whole body (other limits exist for less critical areas of the body, e.g., limb extremities). Radiation protection design features and the health physics programs ensure that the occupational radiation exposures to operating personnel during operation and anticipated operational occurrences will be as low as is reasonably achievable.[3] Table 11 shows that occupational radiation exposures have averaged 0.65 rem per worker per year at 39 operating plants.

Table 10. Comparison of TVA and Bertolett Studies in Nuclear Power Plant Operational Injuries

Coefficient	TVA[a] Mean	TVA[a] Standard Deviation	Bertolett[b]
Fatalities/100 MY[c]	0.0		0.0
Serious cases/100 MY	0.77	0.54	0.55
Lost days/100 MY	23	16.7	14
TWh[d] act/100 MY	2.6		--
Fatalities/TWh act	0.0		--
Serious cases/TWh act	0.29		--
Lost days/TWh act	8.7		--

[a] From Table IV-1, values based on OSHA definitions.

[b] From A.D. Bertolett and R.J. Fox, Electrical World, 182(2), 40-41, July 15, 1974. Values are based on ANSI definitions.

[c] 100 MY = 100 man-years = 200,000 man-hours.

[d] TWh act = billion kilowatt-hours actually generated.

Table 11. Summary of Occupational Exposure Information During 1978 at Pressurized Water Reactor Nuclear Power Plants[4,5,6]

Number of Reactors Included	Average Dose Per Worker (Rems)	Average Collective Dose Per Reactor (Man-Rems)	Average No. Personnel With Measurable Doses	Average Man-Rems Per MWe	Average Rated Capacity (MWe)
39	0.65	428	659*	0.8	723

Area of Exposure

Reactor Operations	Routine Maintenance	Inservice Inspection	Special Maintenance	Radwaste Processing	Refueling
14.1%	21.9%	12.4%	37.5%	4.4%	10.6%

* Includes temporary personnel. (Permanent work force is approximately 230.) The construction work force (2300 average/4300 peak) is not typically exposed to radiation.

Exposures to low-level radiation include those from direct exposure as well as those resulting from airborne radioactivity.

Direct Radiation Exposure Estimates

Direct radiation from components and equipment containing radioactive fluids is the primary source of occupational exposure. Annual doses from direct radiation during the performance of routine functions, such as operation and surveillance, maintenance, radwaste handling, refueling, and inservice inspection experienced on several operating PWR nuclear plants are presented in Table 11.

Exposures From Airborne Radioactivity

Negligible airborne concentrations and, consequently, negligible airborne radioactivity exposures have been experienced in those areas of the auxiliary, radwaste, and turbine buildings that are accessible.[3] Exposures due to airborne radioactivity are possible in the containment and fuel building both during power operation and refueling. However, the design of the plant, operating procedures, and expected limited occupancies in these buildings will minimize exposures to airborne activity and ensure that the doses to an individual from airborne radioactivity are within 10 CFR 20 limits.

Direct Radiation Exposure at Locations Outside Plant Structures

Direct radiation outside plant structures from the containment and the auxiliary, radwaste, and turbine buildings is negligible, compared to that from outside storage tanks.[3] The principal sources of radioactivity not stored in the plant structures are in the reactor makeup water storage tank, the refueling water storage tank, and the condensate storage tank. Technical specifications strictly limit the allowable radioactivity in the tanks to very low levels. These tanks are surrounded by a security fence located far enough from the tanks to yield a dose rate of 0.5 mrem/hr or less at the security fence.[3]

References

1. F.R. O'Donnel and H.C. Hoy, "Occupational Safety Data for Energy Technology Characterization -- Volume I Uranium Technologies," Draft, Oak Ridge National Laboratory, May 1980, Appendix I.
2. A.D. Bertolett and R.J. Fox, "Accident-Rate Sample Favors Nuclear," Electrical World, July 15, 1974, p. 40.
3. "Standard Nuclear Unit Power Plant System (SNUPPS)," Final Safety Analysis Report, October 2, 1979, Chapter 12.
4. NUREG-0109, "Occupational Radiation Exposure at Light Water Cooled Power Reactors," 1969-1975.
5. NUREG-75/032, "Occupational Radiation Exposure At Light Water Cooled Power Reactors," 1969-1974.
6. NUREG-0594, "Occupational Radiation Exposure, Eleventh Annual Report," 1978.

APPENDIX A. COST INFORMATION

Sufficient information is available to approximate the costs for the typical plant from historical data. An extensive effort by the Department of Energy (DOE) and the Nuclear Regulatory Commission (NRC)[1] examined the total costs (capital, fuel, and operating and maintenance) for various plant types and sizes under a range of economic assumptions. The plant most similar to the typical plant in this Environmental Characterization Information Report (ECIR) is a 1139-MWe single unit plant using a Westinghouse pressurized water reactor system. The actual costs for a particular plant may vary significantly from the figures presented in this appendix. Variations in utility preferences, environmental and licensing considerations, site location (in particular, earthquake and tornado design criteria), labor availability, escalation and interest costs, and construction schedules all have major impacts on the actual cost of a given plant.

When the data for the 1139-MWe plant are converted to our 1000-MWe plant size, the result for plant capital cost is $580/kW (1976 dollars) or $580 million. The DOE/NRC study provides an analysis that assumes an 8-percent escalation rate and a 1985 date for first operation. Under these assumptions, correcting for escalation, interest during construction, and contingency, the total (integrated) capital cost for the 1000-MWe plant is $1270/kW, or $1270 million. If the escalation rate were only 5 percent, the capital cost would be $1065/kW, or $1065 million.

Figure A-1 was prepared in another DOE study to show the current projected trend being made by the utilities in the capital costs of all nuclear power plants under construction that have an output of 1000 MWe or greater (the number of samples in the estimates is shown in the figure).[2] A linear least-squares trend line has been fitted to the data showing an estimated annual increase in 1979 dollars of $65/kWe, which is equivalent to an average rise of 8.2 percent per year over the 1980 to 1989 period.

The DOE/NRC study also calculated the total life-cycle costs* for the 1985 plant in mills/kWh (including capital, fuel, and operating and maintenance), assuming an 8-percent escalation and a 12-percent discount rate. As might be expected, this total cost will depend on the portion of time the plant actually operates (capacity factor). The total costs, as a function of capacity, normalized for the 1000-MWe plant are as follows:

---

* Costs for ultimate decommissioning and decontamination are not included; they will vary from plant to plant, depending on factors such as the utility operating philosophy.

BEST DOCUMENT AVAILABLE

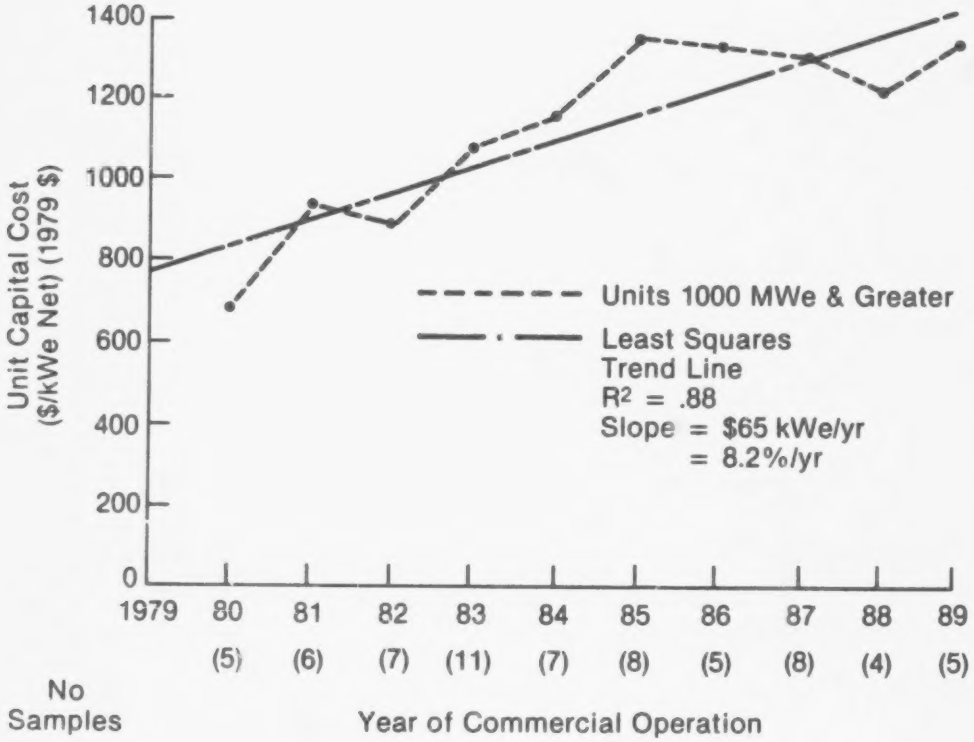

Figure A-1. Current Projected Trend in Capital Costs

Capacity Factor (%)	Total Life-Cycle Costs (8% escalation; 12% discount) 1976 (mills/kWh)
50	81.7
60	72.5
70	65.9
80	60.9

The figures for alternate economic assumptions are as follows:

Capacity Factor (%)	Total Life-Cycle Costs (5% escalation; 10% discount) 1976 (mills/kWh)
50	59.2
60	51.9
70	46.7
80	42.7

References

1. United Engineers and Constructors, Inc., "Total Generating Cost: Coal and Nuclear Plants," Vol. 8 in a Series of 8 Commercial Electric Power Cost Studies, NUREG-0248, COO-2477-12, February 1979.
2. UPDATE, Office of Nuclear Reactor Programs, Department of Energy, March/April 1980, pp. 55-58.

APPENDIX B. COMPARISON OF MAJOR DIFFERENCES IN PWR SYSTEMS

(To Be Added Later)

APPENDIX C. COOLING PONDS

As an alternative to the use of expensive cooling towers, cooling ponds are widely used as a source of circulating water for power plants when land and makeup water are available at a reasonable cost. Cooling ponds also offer the advantage of no cooling tower drift and, therefore, eliminate the environmental impact associated with drift. Unfortunately, cooling ponds have low heat transfer rates requiring large surface areas, are susceptible to siting problems, lose large amounts of water due to solar evaporation, generate large amounts of fog in cold weather, and collect chemical impurities and dissolved solids that must be removed by blowdown.[1]

Area requirements for cooling ponds are typically on the order of 1 to 2 acres per megawatt electric of installed capacity.[2] The major factors affecting cooling pond performance and, therefore, size are surface air temperature, relative humidity, wind conditions, solar radiation, aquatic growth, and erosion.

The evaporation rate for cooling ponds range from 0.40 to 0.60 gal/kWh of waste heat dissipated versus approximately 0.325 gal/kWh for a cooling tower.[3] Spray systems added to cooling ponds increase the heat loss per unit area and hence reduce the land required for a pond by a factor of about 20.[1] However, due to enhanced evaporation, water losses are greater when sprays are used. Water losses average 1 percent year round reaching 1.5 to 2 percent of the amount of sprayed water during the summer months.[1]

A pond area (no sprays) of 2 acres/MWe and an evaporation rate of 0.5 gal/kWh of waste heat is used as representative of the typical power plant.

$$\boxed{\text{Land area} = \begin{pmatrix}\text{Area requirement for site}\\ \text{conditions, acre/MWe}\end{pmatrix}\left(\text{Installed capacity}\right)}$$

For the typical plant,

$$\begin{aligned}\text{Land area} &= (2\ \text{acres/MWe})(1000\ \text{MWe})\\ &= 2000\ \text{acres}\end{aligned}$$

$$\boxed{\text{Evaporation loss} = \begin{pmatrix}\text{Evaporation}\\ \text{loss rate}\end{pmatrix}\begin{pmatrix}\text{Percent heat dissipated}\\ \text{in cooling pond}\end{pmatrix}\begin{pmatrix}\text{Installed thermal}\\ \text{capacity}\end{pmatrix}}$$

For the typical plant,

$$\text{Evaporation loss} = (0.5\ \text{gal/kWh})(24\ \text{hr/day})(0.65\ \text{percent heat loss})(3 \times 10^6\ \text{kWt})$$
$$= 23.4 \times 10^6\ \text{gal/day}$$

On an annual basis at 70-percent capacity

$$\text{Evaporation loss} = (23.4 \times 10^6\ \text{gal/day})(365\ \text{days/yr})(0.7)$$
$$= 5.98 \times 10^9\ \text{gal/yr}$$

These water losses due to evaporation in the ponds are approximately 57 percent greater than the equivalent capacity natural draft cooling tower discussed in item ⑧.

If the number of concentration cycles for the cooling pond is assumed to be the same as the cooling tower calculated in item ⑨ to be 4.3 cycles, then by manipulating the equation in item ⑨, the amount of blowdown in the pond can be calculated as follows

$$W_{BLOWDOWN} = \frac{W_{EVAP}}{N-1} \qquad N = \text{Number of concentration cycles}$$

For the typical plant,

$$W_{BLOWDOWN} = \frac{23.4 \times 10^6\ \text{gal/day}}{4.3 - 1}$$
$$= 7.1 \times 10^6\ \text{gal/day}$$

On an annual basis at 70-percent capacity factor

$$W_{BLOWDOWN} = \frac{5.98 \times 10^9\ \text{gal/yr}}{4.3 - 1}$$
$$= 1.8 \times 10^9\ \text{gal/yr}$$

References

1. Geoffrey Eichholz, Environmental Aspects of Nuclear Power, pp. 241-243
2. University of South Carolina, "A Study of Selected Cooling Pond Design Techniques," SRO-701-1, prepared for U.S. Atomic Energy Commission, June 1973, p. 17.
3. Teknekron Research, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 145.

GLOSSARY

As low as reasonably achievable	Requirement by the Nuclear Regulatory Commission in 10 CFR 50 to reduce occupational and public exposure to radiation to the maximum extent possible within reasonable means even if not doing so would not cause exposures to exceed established limits.
Blowdown	Water that is periodically removed from either the steam generator, cooling towers, or the fossil-fuel boiler to prevent concentration of total dissolved solids.
Boron recycle system	System used to recover boron for recycling. Boron is added to the primary coolant as a neutron absorber for reactivity (reactor) control. As the 3-year reactor fuel cycle progresses and fissionable uranium is depleted, the primary coolant is removed through the reactor coolant letdown line. The letdown coolant is processed in the boron recovery/recycle system through an evaporator, and the boron in the evaporator bottoms is either reused or packaged as solid waste.
Capacity factor	The actual electrical output produced by a power plant in megawatt-hours over a period of time divided by the design output of the plant in megawatt-hours over the same period of time.
Chemical and volume control systems	System that purifies, adjusts chemical content, and controls inventory of reactor coolant water.
Circulating water	Water supplied to the generating plant's main condenser that is cooled by the cooling towers or other heat sinks.
Clarifiers	System used to remove the majority of total suspended solids in the river makeup water.
Cooling tower drift	Aerosols of water (mist) that are discharged to the atmosphere from the cooling towers.
Cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere through the cooling towers.

Curie	Term used to define the amount of a given radioactive material; equivalent to the amount of material that decays at a rate of 3.7×10^{10} disintegrations per second.
Decontamination factor (DF)	The ratio of the initial amount of a nuclide in a stream (specified in terms of concentration or activity of radioactive materials) to the final amount of that nuclide in the stream following treatment by a given process.
Discount rate	A factor in cost accounting formulas used for analyzing the time value of money. Its magnitude depends on the cost of capital, financing schemes, etc.
Escalation	Increases in cost of equipment, materials, labor, etc., as a result of inflation.
Fissile material	Forms of uranium or plutonium (e.g., U-235) that undergo fission in a light-water reactor.
Fission product	A nuclide (usually radioactive) produced either by fission or by subsequent radioactive decay.
Fuel defect	An imperfection in the cladding of nuclear fuel rods.
GALE code	Computer model used by the Nuclear Regulatory Commission to calculate the quantity of radioactive effluents released to the air and water.
Gaseous effluent stream	Processed gaseous wastes containing radioactive materials resulting from the operation of a nuclear power reactor.
HEPA filters	Filters used in gaseous waste streams to remove particulate matter.
Liquid effluent steam	Liquid wastes containing radioactive materials resulting from the operation of a nuclear power reactor (may be processed before release).
Liquid radwaste evaporators	Devices used to concentrate liquid radwaste prior to solidification.
Man-rem	A unit for considering the collective radiation dose received by a group of people. One man-rem is equivalent to the amount of radiation dose received by one person exposed to one rem, two persons exposed to one-half rem, etc.

Net station heat rate ($\dot{Q}$)	Amount of fuel input (in Btu) necessary to generate 1 kWh of electricity.
Plant efficiency	Electrical energy out of the plant to the transmission network divided by total heat energy used to produce the electric energy.
Primary coolant system	Reactor coolant system that transfers the heat from the nuclear reactor to the steam generator.
Radioactive halogens	The isotopes of fluorine, chlorine, bromine, and iodine. The radioactive isotopes of iodine are the key isotopes considered in dose calculations for reactor effluents.
Radioactive noble gases	The radioactive isotopes of helium, neon, argon, krypton, xenon, and radon, which are characterized by their chemical inactivity. The radioactive isotopes of krypton and xenon are the key elements considered in dose calculations.
Radwaste	Waste that is known or suspected to be contaminated with radioactive material.
Reactor coolant letdown	Small portion of the reactor primary cooling system that is continuously purified by the chemical and volume control system or the boron recovery system.
Reactivity	A measurement of the fissioning activity inside the reactor core.
Reactor core	The portion of the reactor where the fissioning of uranium takes place.
Rem	A unit of radiation dose.
Scram	A rapid insertion of the nuclear reactor control rods.
Secondary coolant system	System that transfers the steam generated in the steam generators to the turbine. condenses the steam, and returns it to the steam generator.
Source term	The calculated average quantity of radioactive material released to the environment from a nuclear power reactor during normal operation, including anticipated operational occurrences. The source term is the isotopic distribution of radioactive materials used in evaluating the impact of radioactive releases on the environment.

Spent reactor fuel	Nuclear fuel that has reached its end of useful life in the reactor core.

ACRONYMS AND ABBREVIATIONS

AFR	away from reactor
ANS	American Nuclear Society
ANSI	American National Standards Institute
ALARA	as low as reasonably achievable
Btu	British thermal unit
BWR	Boiling Water Reactor
CFR	Code of Federal Regulations
Ci	curie
cm	centimeter
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
EPA	Environmental Protection Agency
ft	feet
gal	gallon
ha	hectare
HEPA	high efficiency particulate aerosol (filter)
kWh	kilowatt hour
l	liter
lb	pounds
μmhos	micromhos (10^{-6} mhos)
mCi	millicurie (10^{-3} Ci)
mg	milligram (10^{-3} grams)
min	minute
mrem	millirem (10^{-3} rem)
MWe	megawatt-electric (10^{6} watts)
MWt	megawatt-thermal (10^{6} watts)
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
OSHA	Occupational Safety and Health Administration
P	net power delivered to the transmission grid
PWR	Pressurized Water Reactor
PWR-GALE	A computer code: Pressurized Water Reactor Gaseous and Liquid Effluents
$\dot{Q}$	net station heat rate
SNUPPS	Standardized Nuclear Unit Power Plant System
TVA	Tennessee Valley Authority
U^{235}	uranium-235
UO_2	uranium dioxide
$W_{BLOWDOWN}$	cooling tower blowdown
W_{EVAP}	cooling tower evaporation loss
W_{TOW}	cooling tower makeup water
WGPS	Waste Gas Processing System
yr	year

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Oil Shale Surface Retorting

Environmental Characterization Information Report

January 1981

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Safety & Emergency Preparedness
Office of Environmental Assessments
Washington, D.C. 20585

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FOREWORD

This Environmental Characterization Information Report (ECIR) is a synthesis of environmental data and current information relevant to a hypothetical commercial-sized Oil Shale, Surface Retorting Plant (Paraho Process). All of the information used is drawn from published analysis reports and referenced. The report is prototypical of a set of ECIRs that will be developed for a range of fossil, solar, geothermal, nuclear, and conservation energy systems. The ECIRs are designed to have several related purposes: to communicate to all potential users environmental data and information characteristic of an energy system; to provide a framework that can be used to project and environmentally characterize future commercial-sized plants; to present an organized data and information base for application in manual and computer-based analytical systems; and to provide the medium for facilitating development, maintenance, and critical review of the data and information base. A specific purpose of this ECIR is to provide a framework example of analytic procedures that may be used to make future determinations of emissions data and resource requirements pending availability of information from larger oil shale facilities. Although it is realized that new data are continually being produced by oil shale research facilities, only data that have been evaluated and analyzed have been used in this document. It is not intended for use in developing regulations or permits at the local, state, or Federal levels as this process may not achieve commercial status, and the plant configuration described herein is purely hypothetical.

The set of ECIRs is designed to replace the general technical backup volumes formerly supplied with "Technology Characterization, Environmental Information Handbook," DOE/EV-0072, January 1980. Responsibility for the contents and development of an ECIR is assigned to individual technology specialists in the Technology Assessments Division. This ECIR was developed under the direction of Dr. George Rotariu of the Fossil Energy Program staff. In this endeavor, we also draw upon the technical support and assistance of qualified external experts familiar with the energy systems. Technical comments and any additional information that will improve this ECIR should be directed to Dr. George J. Rotariu, Project Officer, (301) 353-5865. Suggestions or recommendations for improving the ECIR concept should be addressed to me.

Dario R Monti

Dario R. Monti
Director, Technology Assessments
Division
Office of Technology Impacts

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I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Oil Shale, Surface Retorting: Paraho Process (Direct Mode) has been prepared from the latest available environmental and technical information collected from a number of sources. The plant chosen for characterization is a 50 x 10^3 bbl/day syncrude equivalent facility.

The process, assumed plant operating parameters, resources needed, and the environmental residuals and products associated with the plant are presented in this section in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 90 percent. Although this capacity factor is assumed to be representative, it does not consider unscheduled shutdowns for repairs of the plant and associated environmental control equipment or factors independent of the plant itself, e.g., reserve requirements.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of energy (syncrude) produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section III. Twenty-one environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions, and a bibliography of cited references. The calculations of allowable emission levels are based on current Federal regulations that are assumed to be applicable to oil shale facilities. At this point in time, there are no New Source Performance Standards for emissions relating to oil shale facilities because commercial oil shale facilities do not currently exist. For information on impending regulations, see Reference 1.

Section IV discusses the overall physical requirements of the plant for land and water; Section V gives the approximate number of personnel involved in constructing and operating a commercial-scale oil shale facility; and Section VI briefly describes the occupational health and safety hazards associated with oil shale mining and processing. The Paraho retorting process, cost information analysis, and various mining techniques are included as appendixes to this report. A glossary and a listing of acronyms and abbreviations used follow the appendixes.

Reference

1. U.S. Department of Energy, Office of Environment, Office of Technology Impacts, "Environmental Issues Briefing Book for Policy Analysis Division," April 1979 (compiled by the Mitre Corporation).

TABLE 1. SUMMARY SHEET

OIL SHALE, SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE)

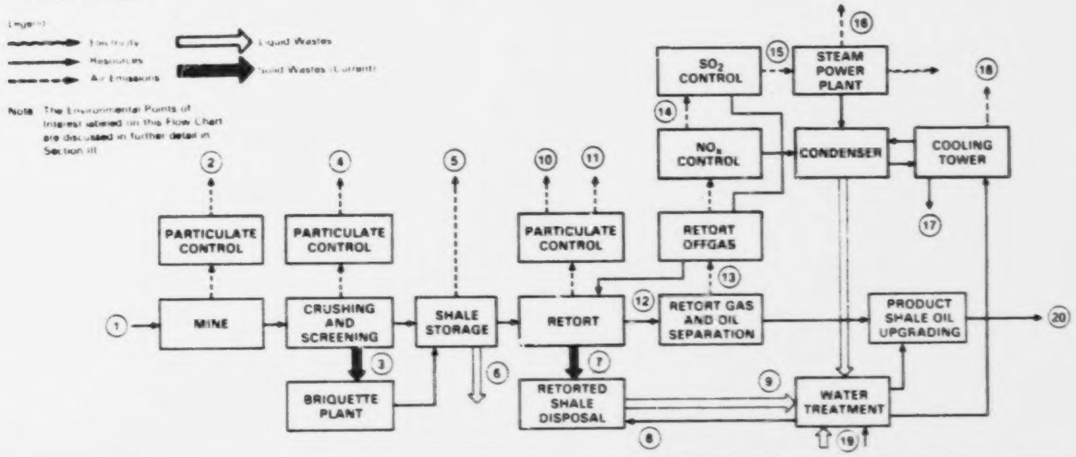
ENERGY SYSTEM DESCRIPTION

Mine-Mouth Plant Located in the Rich Oil Shale Green River Formation; Wetting Agents, Baffled Settling Chambers, Venturi Scrubbers, and Baghouse Filters for Particulate Control; Phosam-W Process for NH_3 Removal (NO_x Control); Stretford Process for H_2S Removal (SO_2 Control); Onsite Solid Waste Disposal; Onsite Water Treatment for Recirculation to Minimize Discharge and External Water Requirements; and Onsite Shale Oil Upgrading Facility. Oil Shale Facilities Are Subject to Future Regulations.

PLANT OPERATING PARAMETERS

Facility Size:	50×10^3 bbl/day syncrude equivalent
Annual Capacity Factor:	90% (assumed)
Shale Oil Extraction Efficiency:	95%
Upgrading From Shale Oil to Syncrude Efficiency:	90%
Plant Lifetime:	25 yr
Feedstock Grade:	28 gal/ton

PROCESS FLOW


Legend
Electricity
Resources
Air Emissions
Liquid Wastes
Solid Wastes (Current)
Note The Environmental Points of Interest labeled on this Flow Chart are discussed in further detail in Section III
MINE
CRUSHING AND SCREENING
BRIQUETTE PLANT
SHALE STORAGE
RETORT
RETORTED SHALE DISPOSAL
PARTICULATE CONTROL
PARTICULATE CONTROL
PARTICULATE CONTROL
RETORT OFFGAS
RETORT GAS AND OIL SEPARATION
NO_x CONTROL
SO_2 CONTROL
STEAM POWER PLANT
CONDENSER
COOLING TOWER
WATER TREATMENT
PRODUCT SHALE OIL UPGRADING
①
②
③
④
⑤
⑥
⑦
⑧
⑨
⑩
⑪
⑫
⑬
⑭
⑮
⑯
⑰
⑱
⑲
⑳

RESOURCES USED

Code No.	Resource	Quantities Used: Annual Usage*: English Units	Metric Units	Per 10^{12} Btu (Energy: syncrude)
	Exposives			
①	ANFO for rubblization	7.8×10^3 tons	7.1×10^3 tonnes	73 tons
	Fuel			
①	Run-of-mine oil shale	29×10^6 tons	26.4×10^6 tonnes	273×10^3 tons
	Diesel fuel for onsite equipment	5.16×10^6 gal	19.53×10^6 liters	48.6×10^3 gal
	Water			
⑲	Makeup water	1.184×10^9 gal (3633 acre-ft)	4.44×10^9 liters	11.2×10^6 gal (343 acre-ft)
	Land			
	Land for mine development	10 acres	total over 25-year plant lifetime	
	Land for retorted shale disposal	1080 acres		
	Land for basic site facilities	140 acres		
	Land affected by mining	5740 acres		
	Personnel			
	Plant construction	2300 man-yr		
	Plant operation	1260 man-yr		
	Control Costs	\$0.9 - \$1.7/bbl (syncrude equivalent)		
	Raw Materials for Construction **Facility Costs**	To Be Added		

*Based on the assumed 90% capacity factor

TABLE 1. (Continued)

OIL SHALE, SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE)

ENVIRONMENTAL RESIDUALS AND PRODUCTS

		Quantities Released			
		Annual Levels*			
Code No.	Residual or Product	English Units	Metric Units	Per 10^{12} Btu (Energy: syncrude)	Regulatory Compliance Levels
	Air Pollutants				
②	Sulfur dioxide (SO_2)	66 tons	60 tonnes	0.62 ton	Not established
	Oxides of nitrogen (NO_x)	1.1×10^3 tons	1×10^3 tonnes	10.3 tons	
	Total suspended particulates (TSP)	56 tons	51 tonnes	0.53 ton	
	Nonmethane hydrocarbons (HC)	66 tons	60 tonnes	0.62 ton	
	Carbon monoxide (CO)	394 tons	358 tonnes	3.7 tons	
④	Particulate from crushing	296 tons	269 tonnes	2.8 tons	
⑤	Dust from shale storage	not quantifiable			
⑩	Particulates from retort	460 tons	418 tonnes	4.3 tons	
⑪	Carbon dioxide (CO_2) from retort	4.1×10^6 tons	3.7×10^6 tonnes	38.5×10^3 tons	↓
⑯	Post-control flue gas constituents				
	• SO_2	2.9×10^3 tons	2.6×10^3 tonnes	27.2 tons	0.28 lb/10^6 Btu
	• NO_x	2.1×10^3 tons	1.9×10^3 tonnes	19.7 tons	0.2 lb/10^6 Btu
	• HC	0.1×10^3 tons	0.09×10^3 tonnes	9.4 tons	Not established
	• CO	1.8×10^3 tons	1.6×10^3 tonnes	16.9 tons	
	• CO_2	1.1×10^6 tons	1.0×10^6 tonnes	10.3×10^3 tons	↓
	Water Discharges and Pollutants				
⑥	Runoff from shale storage	negligible			
⑨	Runoff from retorted shale	114×10^6 gal	433×10^6 liters	1.07×10^6 gal	
⑱	Airborne water from cooling tower drift and evaporation	445×10^6 gal	1691×10^6 liters	4.2×10^6 gal	
	Total suspended solids				25-400 mg/liter**
	Biological oxygen demand				30 mg/liter**
	Oil and grease				10-50 mg/liter**
	Solid Waste				
⑦	Retorted shale	23×10^6 tons	20.9×10^6 tonnes	216×10^3 tons	

Symbols and abbreviations are discussed in the acronyms and abbreviations section.

*Based on the assumed 90% capacity factor.

**Colorado water quality standards.

OCCUPATIONAL SAFETY AND HEALTH

	Underground Mining		Surface Retorting	
	Annual	Per 10^{12} Btu	Annual	Per 10^{12} Btu
Deaths	1.04	0.01	0.21	0.002
Injuries	46.1	0.43	23.3	0.22

UPGRADED SHALE OIL

		Quantity		
		Annual Output*		
Code No.	Product	English Units	Metric Units	Per 10^{12} Btu (Energy: syncrude)
⑳	Syncrude	16.4×10^6 bbl	2.6×10^9 liters	154×10^3 bbl

*Based on the assumed 90% capacity factor.

II. INTRODUCTION

Oil shale is a fine-grained sedimentary rock containing varying amounts of organic material called kerogen. When heated to about 900°F, a minimal residence time is required for the kerogen to fully decompose into hydrocarbons and a carbonaceous residue. Upon cooling, these hydrocarbons condense into a heavy liquid called shale oil, which after upgrading, can be refined into different fuel products, such as gasoline, jet fuel, and diesel fuel.

Although there are several different techniques for mining and retorting oil shale, surface retorting is, technologically speaking, well along the path to commercialization; however, more research, development, and demonstration (RD&D) is needed.[1] This document presents a typical surface retorting technology, the Paraho process -- one of several surface retorting technologies considered to be approaching commercialization. The use of the Paraho process in this report should not be construed as meaning that the process is now or will be commercial.

It is important to remember that there is currently no commercial oil shale industry in the United States; the industry is still in the initial stages of development. The data base on oil shale activities exists for relatively small-scale facilities and must be considered first-generation information. More accurate pollutant data are needed and this is currently being obtained through sponsored RD&D by the U.S. Department of Energy, other Federal agencies, and private industry. Therefore, when estimates are given for a commercial-sized system capable of producing 50×10^3 bbl/day syncrude equivalent, the data have to be scaled up to a system this size. Exactly how this should be done is unclear; for lack of a better method, scaling (when required) is assumed to be linear. In addition, there are instances when data needed to define emission factors are deficient (e.g., mining operations), and for these cases, information is taken from similar operations (e.g., rock, coal).[2]

Thus, even though the best information that is presently available is used in this report, note that environmental problems associated with air emissions, water quality, and long-term solid waste disposal exist. The approach taken is to present one possible solution to these problems; the actual components and operating characteristics of a full-sized commercial system may differ from the system described herein. This document, however, still serves a useful function in that reasonable first order approximations for resource requirements and pollutant, and residual emissions are delineated, and an accurate, qualitative description of oil shale activities associated with the present Paraho process is given. As better information becomes available from demonstration facilities, it will be incorporated in future updates of this document.

References

1. U.S. Department of Energy, Assistant Secretary for Fossil Energy, Assistant Secretary for Environment, "Environmental Development Plan for Oil Shale," DOE/EDP-0051, November 1979, pp. 2, 14, 18-23.

2. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts/Pacific Northwest Laboratory, "Draft, Task Report for Technology Assessment of Oil Shale Development, Vol. 1, Technology Characterization," prepared under Contract No. EY-76-C-06-1830, November 1979, Chapter I, pp. 5 and 6.

III. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The Department of Energy has stated that the Paraho process is one of the surface retorting techniques that show potential for further development toward commercialization.[1] Based on available information about the Paraho process in particular, and other surface retorting schemes in general, a composite 50 x 10^3 bbl/day syncrude equivalent facility is described. The plant is assumed to be a mine-mouth facility located in the rich oil shale Green River Formation area with onsite capabilities to upgrade the shale oil into premium syncrude suitable for processing in a conventional petroleum refinery. Facilities are also available to upgrade the retort gas so it can be combusted in an onsite boiler to generate all utility requirements. Pollutant emission controls assumed for this plant have been used in commercial industries and are well established. The shale used in the characterization has a Fisher assay of 28 gal/ton; the retorting process has a recovery efficiency of 95 percent; and the conversion of shale oil to syncrude has a process efficiency of 90 percent.[2,3]

Environmental points of interest have been identified in Figure 1 and are discussed in the following sections. Items ① and ② deal with mining; ③ and ④ deal with shale preparation, ⑤ and ⑥ deal with onsite shale storage, ⑦ through ⑲ deal with the retort and pollutant controls and ⑳ deals with upgrading the shale oil to syncrude.

A description of the Paraho retorting process is given in Appendix A, cost information for the plant is given in Appendix B, and options for mining oil shale are presented in Appendix C.

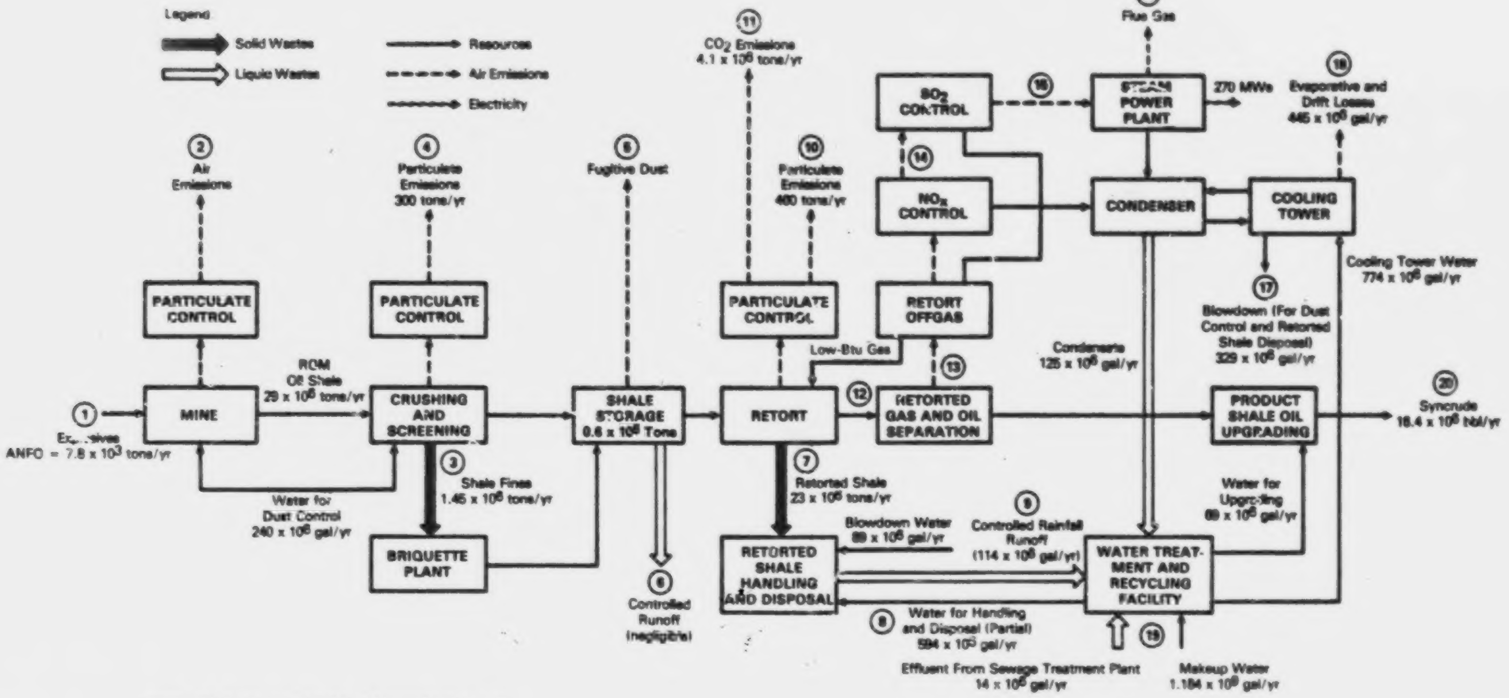
References

1. R.C. Porter, "DOE Tells Superior, Paraho to Move Ahead With Oil Shale Designs," DOE News, R-80-115, June 13, 1980.

2. Heistand, R.N., and R.A. Atwood, "Paraho Environmental Data, Part I, Process Characterization," DOE/EV-0086, June 1980, p. 2-6.

3. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 23-26.

FIGURE 1.
PROCESS FLOW CHART WITH ENVIRONMENTAL POINTS OF INTEREST
– OIL SHALE SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE) –
90% CAPACITY FACTOR


Legend
Solid Wastes
Liquid Wastes
Resources
Air Emissions
Electricity
① Explosives ANFO = 7.8 x 10³ tons/yr
MINE
② Air Emissions
PARTICULATE CONTROL
ROM Oil Shale 29 x 10⁶ tons/yr
Water for Dust Control 240 x 10⁶ gal/yr
CRUSHING AND SCREENING
④ Particulate Emissions 300 tons/yr
PARTICULATE CONTROL
③ Shale Fines 1.45 x 10⁶ tons/yr
BRIQUETTE PLANT
SHALE STORAGE 0.6 x 10⁶ Tons
⑤ Fugitive Dust
⑥ Controlled Runoff (negligible)
RETORT
PARTICULATE CONTROL
⑪ CO2 Emissions 4.1 x 10⁶ tons/yr
⑩ Particulate Emissions 400 tons/yr
Low-Btu Gas
⑫
RETORTED GAS AND OIL SEPARATION
⑬
RETORT OFFGAS
NOx CONTROL
⑭
SO2 CONTROL
⑮
STEAM POWER PLANT
⑯ Flue Gas
270 MWe
CONDENSER
COOLING TOWER
⑱ Evaporative and Drift Losses 445 x 10⁶ gal/yr
Cooling Tower Water 774 x 10⁶ gal/yr
⑰ Blowdown (For Dust Control and Retorted Shale Disposal) 329 x 10⁶ gal/yr
Condensate 125 x 10⁶ gal/yr
PRODUCT SHALE OIL UPGRADING
⑳ Syncrude 18.4 x 10⁶ bbl/yr
⑦ Retorted Shale 23 x 10⁶ tons/yr
RETORTED SHALE HANDLING AND DISPOSAL
Blowdown Water 89 x 10⁶ gal/yr
⑨ Controlled Rainfall Runoff (114 x 10⁶ gal/yr)
⑧ Water for Handling and Disposal (Partial) 594 x 10⁶ gal/yr
WATER TREATMENT AND RECYCLING FACILITY
Water for Upgrading 89 x 10⁶ gal/yr
⑲
Effluent From Sewage Treatment Plant 14 x 10⁶ gal/yr
Makeup Water 1.184 x 10⁶ gal/yr

NOTE: The Environmental Points of Interest labeled on this Flow Chart are discussed in further detail in Section III.

① Mining of Oil Shale

To rubblize the 29 x 10^6 ton/yr of oil shale needed to produce 16.4 x 10^6 bbl/yr of syncrude, 7.8 x 10^3 ton/yr of ammonium nitrate fuel oil explosives are required.

The mine is assumed to be a room-and-pillar mine.[1] This method of underground mining is well established and consists of drilling, charging, and blasting; loading and hauling; and roof bolting and scaling.[1-3] Fresh air ventilation is a continuous operation for miner safety. (See Appendix C for other mining techniques.)

Rooms are approximately 60 ft wide by 60 to 90 ft high with pillars approximately 60 to 80 ft wide. Mining is conducted in two benches, each 30 to 45 ft deep.[1] The upper bench is mined first by drilling blastholes horizontally into the walls of a production room and breaking the shale loose with explosives. The broken shale is loaded into trucks and transported to the primary crushing stage. The pillar wall and roof are inspected and scaled to remove loosened shale. Holes are drilled into the roof and bolts are inserted to ensure its integrity, thereby protecting the miners from cave-ins. The lower bench is mined by following a similar sequence, except the blastholes are drilled into the floor of the upper bench and additional roof bolting is not required.[4] This mining system results in an ore recovery of up to 70 percent.[1]

To determine the quantity of explosives needed to rubblize enough oil shale to produce 50 x 10^3 bbl/day syncrude oil equivalent, the Fischer assay of the oil shale, the retorting recovery efficiency, and the upgrading conversion to syncrude efficiency must be known. The Fischer assay for the shale in the Green River area averages 28 gal/ton; the Paraho retorting process has a recovery efficiency of 95 percent; and the conversion of shale oil to syncrude has a process efficiency of 90 percent.[5,6] Therefore, because the heating values of shale oil and crude petroleum are approximately the same,[7]

Quantity of oil shale (shale feed rate)

$$= \frac{\text{(barrels syncrude equivalent)(gal/bbl)}}{\text{(Fischer assay of shale)(retort recovery efficiency)(conversion to syncrude efficiency)}}$$

$$= \frac{(50 \times 10^3 \text{ bbl/day})(42 \text{ gal/bbl})}{(28 \text{ gal/ton})(0.95)(0.9)}$$

$$= 88 \times 10^3 \text{ tons/day}$$

The plant capacity factor is assumed to be 90 percent.[6] Hence, on a yearly basis,

$$\begin{aligned}\text{Quantity of oil shale (shale feed rate)} &= (88 \times 10^3\ \text{tons/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 29 \times 10^6\ \text{tons/yr}\end{aligned}$$

The amount of syncrude oil equivalent that this quantity of oil shale is capable of yielding, is given by

$$\begin{aligned}\text{Barrels of syncrude equivalent} &= (50 \times 10^3\ \text{bbl/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 16.4 \times 10^6\ \text{bbl/yr}\end{aligned}$$

The blasting agent, an ammonium nitrate fuel oil mixture, ANFO, which is used to rubblize the shale, is loaded pneumatically into holes 4.5 in. wide and 30 ft deep. Based on experimental data, approximately 0.54 lb of ANFO per ton of rubblized shale is required.[1] Hence, on a daily basis,

$$\begin{aligned}\text{Quantity of ANFO} &= (\text{shale feed rate})(\text{ANFO-shale ratio})/(\text{lb/ton}) \\ &= (88 \times 10^3\ \text{tons shale/day})(0.54\ \text{lb/ton shale})/(2 \times 10^3\ \text{lb/ton}) \\ &= 23.8\ \text{tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Quantity of ANFO} &= (23.8\ \text{tons/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 7.8 \times 10^3\ \text{tons/yr}\end{aligned}$$

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts/Pacific Northwest Laboratory, "Draft, Task Report for Technology Assessment of Oil Shale Development, Vol. 1, Technology Characterization," prepared under Contract No. EY-76-C-06-1830, November 1979, Chapter I, pp. 1-4, Chapter IV, pp. 1-4.

2. R.N. Heistand and R.A. Atwood, "Paraho Environmental Data, Part II, Air Quality," DOE/EV-0086, June 1980, p. 2-1.

3. U.S. Department of Energy/Assistant Secretary for Fossil Energy, "Draft EIS, Paraho Research Project at the Anvil Points Oil Shale Facility," June 9, 1980, pp. 2.5-2.8.

4. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Assessment, "An Assessment of Oil Shale Technologies," June 1980, pp. 125-127.

5. R.N. Heistand and R.A. Atwood, "Paraho Environmental Data, Part I, Process Characterization," DOE/EV-0086, June 1980, p. 2-6.

6. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 23-26.

7. T. Baumeister and L.S. Marks, editors, Standard Handbook for Engineers, 7th Edition, McGraw Hill Book Company, New York, 1967. pp. 7.22, 7.30.

② Air Emissions From Mining

The controlled residual pollutants emitted to the atmosphere as a result of mining operations are

Particulates	*56 tons/yr*
Hydrocarbons	*66 tons/yr*
Sulfur dioxide	*66 tons/yr*
Carbon monoxide	*394 tons/yr*
Nitrogen oxides	*1.1×10^3 tons/yr*

Particulates

Drilling, loading, and hauling are the mining operations that generate particulates.[1] Charging, scaling, and roof bolting also produce particulates, but in minor amounts.[2] Wet suppression and a baffled settling system, which have a combined efficiency of 98.5 percent, are the control measures used.[1] Approximately 5.2 gal of water per ton of shale mined are required for particulate control.[1,3] This water will be piped from an existing reservoir above the mine.[4] On a daily basis,

$$\boxed{\begin{aligned} \text{Water for dust control} &= (5.2\ \text{gal/ton})(\text{shale feed rate}) \\ &= (5.2\ \text{gal/ton})(88 \times 10^3\ \text{tons/day}) \\ &= 0.46 \times 10^6\ \text{gal/day} \end{aligned}}$$

On a yearly basis,

$$\boxed{\begin{aligned} \text{Water for dust control} &= (0.46 \times 10^6\ \text{gal/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 151 \times 10^6\ \text{gal/yr} \end{aligned}}$$

On a daily basis, (dust) particulate emissions are estimated to be[1]

$$\boxed{\begin{aligned} \text{Particulates (dust)} &= (\text{emission factor})(\text{shale feed rate})(1\text{-control efficiency})/(\text{lb/ton}) \\ &= (1.9 \times 10^{-2}\ \text{lb/ton})(88 \times 10^3\ \text{tons/day})(1-0.985)/(2 \times 10^3\ \text{lb/ton}) \\ &= 12.5 \times 10^{-3}\ \text{tons/day} \end{aligned}}$$

Note that the emission factor is the sum of the mining emission factor[5] (0.009 lb/ton) and blasting emission factor[6] (0.01 lb/ton).

In addition, particulates will emanate from permissible diesel-powered mine equipment at the rate of 22 lb/10^3 gal of diesel fuel.[1] If the amount of diesel fuel used is 15.7 x 10^3 gal/day, then (diesel) particulate emissions on a daily basis are[1]

$$\begin{aligned}\text{Particulates (diesel)} &= \text{(emission factor)(diesel fuel consumption rate)/(lb/ton)}\\ &= (22\ \text{lb}/10^3\ \text{gal})(15.7 \times 10^3\ \text{gal/day})/(2 \times 10^3\ \text{lb/ton})\\ &= 0.17\ \text{ton/day}\end{aligned}$$

Thus, total particulate emissions on a daily basis are

$$\begin{aligned}\text{Particulates} &= \text{particulates (dust)} + \text{particulates (diesel)}\\ &= (12.5 \times 10^{-3}\ \text{tons/day}) + (0.17\ \text{ton/day})\\ &= 0.17\ \text{ton/day}\end{aligned}$$

On a yearly basis, total particulate emissions are

$$\begin{aligned}\text{Particulates} &= (0.17\ \text{ton/day})(0.9\ \text{capacity factor})(365\ \text{days/yr})\\ &= 56\ \text{tons/yr}\end{aligned}$$

Other Emissions

Mine equipment using diesel fuel as a power source in combustion engine drives results in the formation of hydrocarbons (HC), sulfur dioxide (SO_2), carbon monoxide (CO), and nitrogen oxides (NO_x). The only controls used for these pollutants are those incorporated in the equipment by the manufacturer. In addition to this source of emissions for nongassy mines, blasting will also contribute to NO_x and CO production. These quantities are relatively small and controls are therefore not required. Based on emission factors given in Reference 1, the pollutant emissions from the mine equipment, on a daily basis, are given by

$$
\begin{aligned}
\text{Pollutant} &= (\text{emission factor})(\text{diesel fuel consumption rate})/(\text{lb/ton}) \\
\text{HC} &= (28\ \text{lb}/10^3\ \text{gal})(15.7 \times 10^3\ \text{gal/day})/(2 \times 10^3\ \text{lb/ton}) \\
&= 0.2\ \text{ton/day} \\
SO_2 &= (31\ \text{lb}/10^3\ \text{gal})(15.7 \times 10^3\ \text{gal/day})/(2 \times 10^3\ \text{lb/ton}) \\
&= 0.2\ \text{ton/day} \\
\text{CO} &= (90\ \text{lb}/10^3\ \text{gal})(15.7 \times 10^3\ \text{gal/day})/(2 \times 10^3\ \text{lb/ton}) \\
&\quad + (2.1 \times 10^{-2}\ \text{lb/lb ANFO})(23.8\ \text{tons ANFO/day}) \\
&= 1.2\ \text{tons/day} \\
NO_x &= (428\ \text{lb}/10^3\ \text{gal})(15.7 \times 10^3\ \text{gal/day})/(2 \times 10^3\ \text{lb/ton}) \\
&\quad + (1.6 \times 10^{-3}\ \text{lb/lb ANFO})(23.8\ \text{tons ANFO/day}) \\
&= 3.4\ \text{tons/day}
\end{aligned}
$$

On a yearly basis,

$$
\begin{aligned}
\text{HC} &= (0.2\ \text{ton/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\
&= 66\ \text{tons/yr} \\
SO_2 &= (0.2\ \text{ton/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\
&= 66\ \text{tons/yr} \\
\text{CO} &= (1.2\ \text{tons/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\
&= 394\ \text{tons/yr} \\
NO_x &= (3.4\ \text{tons/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\
&= 1.1 \times 10^3\ \text{tons/yr}
\end{aligned}
$$

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts/Pacific Northwest Laboratory, "Draft, Task Report for Technology Assessment of Oil Shale Development, Vol. I, Technology Characterization," prepared under Contract No. EY-76-C-06-1830, November 1979, Chapter I, pp. 1-4, Chapter IV, pp. 1-4.

2. Personal communication, Edwin Piper (Energy Development Consultants, Inc., Golden, Colorado), September 1980.

3. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, p. 237.

4. U.S. Department of Energy/Assistant Secretary for Fossil Energy, "Draft EIS, Paraho Research Project at the Anvil Points Oil Shale Facility," June 9, 1980, pp. 5.4-5.6.

5. P. Marshall and J.P.T. Agapito, "Plant and Mine Studies, Parachute Creek, Colorado Colony Development Operation, EIA," Appendix 14, 1974.

6. R.F. Charken, E.B. Cook, and T.C. Ruhe, "Toxic Fumes From Explosives, Ammonium Nitrate Fuel Oil Mixture," Bureau of Mines, RI 7867, 1974.

Shale Fines From Crushing and Sizing

hale fines resulting from crushing and sizing operations amount to .4 x 10^3 tons/day or about 5 percent of the total shale crushed.

fter mining the oil shale, it has to be properly crushed and sized. The araho process will incorporate two crushing stages: one in the mine and one xternal to it.[1] The primary crusher will be located in the mine and be of e single or double roll type crusher. The product from the first stage of ushing will be -10. in. This product will enter an ore raise, which will ansport it to a storage site located on the surface. The crushed shale will conveyed through a conveyor adit to the secondary crushing and screening cilities, which are located outside the mine. Here the shale is further ushed by a double roll crusher and sized to a nominal +3/8 in., -3. in. and n be considered a clean retort feed.[2] Once the shale leaves the secondary ushing and screening facilities, it is sent directly to be retorted.

ale particles smaller than 3/8 in. are too small to be properly retorted in e Paraho retort. Although 8 to 10 percent of shale fines may be produced mining and more in crushing (to reach a total of about 15 percent), the ale fines rejected by the screening facility constitute about 5 percent of e total shale crushed.[3]

Shale fines = (percent shale rejected)(shale feed rate)
= (0.05)(88 x 10^3 tons/day)
= 4.4 x 10^3 tons/day

n a yearly basis,

Shale fines = (4.4 x 10^3 tons/day)(0.9 capacity factor)(365 days/yr)
= 1.45 x 10^6 tons/yr

ather than send these fines to the retorted shale storage pile, economics ndicates that it would be better to send them to an onsite facility, where hey can be briquetted with shale oil heavy ends as a binder and then used n the retort.[4]

References

1. C.C. Shih, J.E. Cotter, C.H. Prien, and T.D. Nevens, "Technological Overview Reports for Eight Shale Oil Recovery Processes," EPA-600/7-79-075, March 1979, p. 2.6.

2. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts/Pacific Northwest Laboratory, "Draft, Task Report for Technology Assessment of Oil Shale Development, Vol. 1, Technology Characterization," prepared under Contract No. EY-76-C-06-1830, November 1979, Chapter II, pp. 1-5, Chapter IV, pp. 5-7.

3. U.S. Department of Energy/Assistant Secretary for Fossil Energy, "Draft EIS, Paraho Research Project at the Anvil Points Oil Shale Facility," June 9, 1980, p. 2.16.

4. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 30, 38, 39.

④ Particulate Emissions From Crushing

Particulate emissions from crushing operations are 300 tons/yr.

Crushing operations are a source of particulate emissions. All crushing and screening operations are enclosed, and all materials are transported by covered conveyors. Dust controls that are used by Paraho are baghouse filters (BF) and wet suppression and baffled settling (WSBS). Both controls are used in series inside the mine for the primary crusher, but only baghouse filters are used for the secondary crusher.[1,2]

Particulate emissions on a daily basis are[2]

$$
\begin{aligned}
\text{Particulates} &= (\text{emissions from primary crusher}) + (\text{emissions from secondary crusher}) \\
&= [(\text{emission factor})(\text{shale feed rate})(1\text{-BF control efficiency}) \\
&\quad (1\text{-WSBS control efficiency}) + (\text{emission factor})(\text{shale feed rate}) \\
&\quad (1\text{-BF control efficiency})]/(\text{lb/ton}) \\
&= [(0.5\ \text{lb/ton})(88 \times 10^3\ \text{tons/day})(1-0.99)(1-0.985) \\
&\quad + (1.95\ \text{lb/ton})(88 \times 10^3\ \text{tons/day})(1-0.99)]/(2 \times 10^3\ \text{lb/ton}) \\
&= 0.9\ \text{ton/day}
\end{aligned}
$$

On a yearly basis,

$$
\begin{aligned}
\text{Particulates} &= (0.9\ \text{ton/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\
&= 296\ \text{tons/yr}
\end{aligned}
$$

If the water used for dust control is 3 gal/ton, then the water requirement on a daily basis is[1,2]

$$
\begin{aligned}
\text{Water} &= (\text{dust control factor})(\text{shale feed rate}) \\
&= (3.0\ \text{gal/ton})(88 \times 10^3\ \text{tons/day}) \\
&= 0.27 \times 10^6\ \text{gal/day}
\end{aligned}
$$

On a yearly basis,

$$
\begin{aligned}
\text{Water} &= (0.27 \times 10^6\ \text{gal/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\
&= 89 \times 10^6\ \text{gal/yr}
\end{aligned}
$$

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 38, 39, 237.

2. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts/Pacific Northwest Laboratory, "Draft, Task Report for Technology Assessment of Oil Shale Development, Vol. 1, Technology Characterization," prepared under Contract No. EY-76-C-06-1830, November 1979, Chapter IV, pp. 5 and 6.

⑤ Fugitive Dust From Onsite Shale Storage

It is not possible to accurately quantify the fugitive dust emissions from the shale storage area. Wind erosion resulting in airborne dust should not be a significant air pollution source for active piles if dust control measures are maintained.

Storage facilities will be required in order to meet shale requirements on a continuous basis. Open stockpiles will have the capacity to support retort operations for up to a week's duration.[1] Hence, the maximum amount of shale contained in the stockpile at any one time is given by

$$\boxed{\text{Stored shale, ton} = (\text{7 days storage})(\text{shale feed rate})}$$

For the Paraho plant,

$$\text{Stored shale} = (\text{7 days storage})(88 \times 10^3 \text{ tons/day})$$
$$= 0.6 \times 10^6 \text{ tons}$$

Due to open stockpiling of crushed oil shale, there will be fugitive dust emissions. Dust emissions can be controlled through the use of water sprays and polymer or latex solutions.[2] The dust emissions from an open storage pile are not, in general, quantifiable. They are, however, proportional to the exposed surface area of the shale pile and wind velocity.[3]

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts/Pacific Northwest Laboratory, "Draft, Task Report for Technology Assessment of Oil Shale Development, Vol. 1, Technology Characterization," prepared under Contract No. EY-76-C-06-1830, November 1979, Chapter II, pp. 4 and 5.
2. U.S. Environmental Protection Agency Oil Shale Work Group, "Pollution Control Guidance for Oil Shale Development, Revised Draft Report," EPA/ORD/IERL-Ci, July 1979, pp. 7-5 and 6.
3. U.S. Environmental Protection Agency, "Survey of Fugitive Dust from Coal Mines," EPA-908/1-78-003, February 1978, pp. 2 and 56.

⑥ Controlled Runoff From Onsite Shale Storage

The quantity of liquid runoff from the raw shale storage area is negligible.

Subsurface water will be kept away from the stockpile by either a clay or impermeable membrane liner. This liner will also be used to control leachate that filters through the raw shale storage pile. Water that falls on the surface of the shale pile will be lost to the air through evaporation or drained to a peripheral channel where it can be routed to the water treatment system. This water may contain suspended and dissolved solids, be slightly basic, and contain chemicals used for dust control. The receiving water treatment system is designed to handle such pollutants through settling, neutralization, and blending to achieve acceptable water quality for recycling uses in the system.

The quantity of runoff is proportional to the surface area of the storage pile and the relative quantity of precipitation at the site. If the density of raw shale is approximately[1,2] 140 lb/ft^3, then the volume of the storage pile is given by

$$\begin{aligned} V &= (\text{amount of shale stored})/(\text{density of raw shale}) \\ &= (0.6 \times 10^6 \text{ tons})(2 \times 10^3 \text{ lb/ton})/(140 \text{ lb/ft}^3) \\ &= 8.6 \times 10^6 \text{ ft}^3 \end{aligned}$$

which is roughly equivalent to a cube with a side 200 ft long. The average rainfall[2] in the Green River area is 14 in./yr and if all of this rain is captured as runoff, then

$$\begin{aligned} W_{RUN} &= (\text{surface area, top})(\text{rainfall rate})/[(\text{in./ft})(\text{lb/gal})] \\ &= (200 \text{ ft})^2(14 \text{ in./yr})(62.4 \text{ lb/ft}^3)/[(12 \text{ in./ft})(8.34 \text{ lb/gal})] \\ &= 0.4 \times 10^6 \text{ gal/yr} \end{aligned}$$

This quantity of water is relatively small and is therefore neglected in all calculations involving water balances.

References

1. U.S. Environmental Protection Agency/Office of Research and Development, "Oil Shale and the Environment," EPA-600/9-77-033, October 1977, p. 16.
2. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, p. 338.

⑦ Disposal of Retorted Shale

After the retorting of oil shale, approximately 23 x 10^6 tons of retorted shale have to be properly disposed of per year.

As stated in item ①, Mining of Oil Shale, 88 x 10^3 ton/day of oil shale have to be retorted to generate 50 x 10^3 bbl/day syncrude equivalent. After retorting, approximately 81 percent, by weight, of this raw shale has to be disposed of in an environmentally acceptable manner.[1] The retorted shale produced on a daily basis is given by

Retorted shale = (retorted shale factor)(shale feed rate)

= (0.81 retorted shale factor)(88 x 10^3 tons/day)

= 71 x 10^3 tons/day

On a yearly basis,

Retorted shale = (71 x 10^3 tons/day)(0.9 capacity factor)(365 days/yr)

= 23 x 10^6 tons/yr

Retorted shale has to be managed to avoid pollution from surface erosion (wind and water) and subsurface leaching of soluble salts.[2] Retorted shale contains about 20 lb/ton of readily leachable salts, roughly five times that leachable from raw oil shale.[3] In addition, the carbonaceous component of retorted shale contains organic substances that can be extracted by water.[4] Recent data indicate that retorted shale keeps dissolving.

The Paraho process disposal plan calls for the construction of a leachate-impervious lining of compacted retorted shale in a valley disposal area and a cross-valley earthen dam, also of retorted shale, to be built at the mouth of the valley.[5] This disposal site will be capable of handling all of the retorted shale generated by a 50 x 10^3 bbl/day plant over the 25-year life of the plant. As an example, the retorted shale bed depth will be 530 ft, retention dam height 364 ft, and site surface area 1080 acres. The retorted shale used for the construction of the dam will be compacted to a density of 90 lb/ft^3 and will have a permeability of 9.7 x 10^{-8} cm/sec.[1] The dam outer face will be covered with a 1-ft thick water-stabilized retorted shale mixture, which further protects against leaching and erosion. The entire disposal area surface behind the dam is also covered to a depth of 1 foot with the same mixture, after removal of the native soil cover. The dam is built up slowly as the retorted shale disposal pile depth increases, avoiding creation of an area behind the dam that would retain runoff water. A catchment basin with a capacity of about 300 acre-ft would contain any runoff water. After being dumped and compacted in the shale-lined void behind the dam, the retorted shale will be vegetated.[1] The vegetation process will consist of leaching salts from the top layer of the shale pile; applying a soil layer for plants with such additives as soil conditioners, native microorganisms, topsoil, and fertilizers; selecting a mixture of native and imported plants compatible with local climate and soil conditions; protecting surfaces with mulches; installing fences to ward off grazing animals during the early period of growth; and irrigating the planted area for 2 years or more to establish a viable root system.[2,6]

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 41, 338, and 357.

2. U.S. Environmental Protection Agency/Office of Research and Development/Industrial Environmental Research Laboratory, Cincinnati, "Lysimeter Study on the Disposal of Paraho Retorted Oil Shale," EPA-600/7-79-188, August 1979, pp. 1-5, 28, 29.

3. K.W. Crawford, C.H. Prien, L.B. Baboolal, C.C. Shih, and A.A. Lee, "A Preliminary Assessment of the Environmental Impacts from Oil Shale Developments," EPA-600/7-77-069, TRW and Denver Research Institute, prepared for the U.S. Environmental Protection Agency, Office of Research and Development, Cincinnati, Ohio, July 1977, pp. 87-91.

4. T.F. Yen, editor, Science and Technology of Oil Shale, Ann Arbor Science Publishers, Inc., Michigan, 1976, pp. 143-144.

5. U.S. Department of Energy/Assistant Secretary for Fossil Energy, "Draft Environmental Impact Statement: The Paraho Research Project at the Anvil Points Oil Shale Facility," June 9, 1980, pp. 2.12-2.16.

6. National Research Council, National Academy of Sciences, "Surface Mining of Non-Coal Minerals, Appendix II: Mining and Processing of Oil Shale and Tar Sands," ISBN 0-309-03037-4, 1980, pp. 122-125.

⑧ Water Requirements for Retorted Shale and Sludge Moistening and Disposal

The water requirements for retorted shale and sludge moistening and disposal are 683 x 10^6 gal/yr. Approximately 20 percent of this amount comes from the cooling tower blowdown and the remainder from the water treatment and recycling facility.

For every ton of oil shale that is retorted, approximately 0.81 ton of solid waste, that is, retorted shale, has to be properly disposed of.[1] The retorted shale leaves the retorts at approximately 380°F and is sent to a moisturizer where approximately 5 to 10 percent water is added for cooling and dust control.[1] The water required for this process is given by

$$\begin{aligned} W_{MOIST} &= \text{(shale feed rate)(retorted shale fraction)(water for cooling and dust control)} \\ &\quad \text{(lb/ton)/(lb/gal)} \\ &= (88 \times 10^3 \text{ tons shale/day})(0.81 \text{ ton retorted shale/ton mined shale}) \\ &\quad (0.1 \text{ water})(2 \times 10^3 \text{ lb/ton})/(8.34 \text{ lb/gal}) \\ &= 1.72 \times 10^6 \text{ gal/day} \end{aligned}$$

The water required for vegetation of the retorted shale is assumed to be approximately 5 gal/ton retorted shale per day.[1] The water required per day for this purpose is given by

$$\begin{aligned} W_{VEG} &= \text{(shale feed rate)(retorted shale fraction)(water for vegetation)} \\ &= (88 \times 10^3 \text{ tons shale/day})(0.81 \text{ ton retorted shale/ton mined shale})(5 \text{ gal/ton}) \\ &= 0.36 \times 10^6 \text{ gal/day} \end{aligned}$$

The total daily water requirements for disposal of retorted shale is given by

$$\begin{aligned} W_{TOTAL} &= W_{MOIST} + W_{VEG} \\ &= (1.72 \times 10^6 \text{ gal/day}) + (0.36 \times 10^6 \text{ gal/day}) \\ &= 2.08 \times 10^6 \text{ gal/day} \end{aligned}$$

The total yearly water requirements for the disposal of retorted shale are

$$\begin{aligned} W_{TOTAL} &= (2.08 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 683 \times 10^6 \text{ gal/yr} \end{aligned}$$

Low-quality water is available from the cooling tower blowdown and from the water treatment and recycling facility to meet the requirements for retorted shale disposal. The cooling tower blowdown can make 0.27×10^6 gal/day of water available so that the water treatment and recycling facility must make up the balance of 1.81×10^6 gal/day.[1]

Thus, on a yearly basis, the cooling tower blowdown water available for shale disposal is

$$\begin{aligned} W_{BLOW} &= (0.27 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 89 \times 10^6 \text{ gal/yr} \end{aligned}$$

and the recycled water from the water treatment and recycling facility available for shale disposal is

$$\begin{aligned} W_{SHALE\ DISPOSAL} &= (1.81 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 594 \times 10^6 \text{ gal/yr} \end{aligned}$$

Reference

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 32-59 and 234-243.

⑨ Controlled Water Runoff From Retorted Shale Disposal Site

The controlled water runoff from the retorted shale disposal site available for use in the Paraho process is 114 x 10^6 gal/yr.

The retorted shale disposal site includes a catchment basin to contain runoff water and to provide for management of leachate and storm runoff from the disposal area. Generally, the water collected would be used for dust control in the area, but heavy runoff due to rainfall is incorporated into the water use of the Paraho process.[1] It is estimated that the rainfall on 300 acres of the disposal site can be collected and used in the process. Assuming a rainfall of 14 in./yr, during the year a total of 350 acre-ft of water would be available to reduce the water requirements from available local sources. The water available from the management of the disposal site rainfall runoff is given by

$$\begin{aligned} W_{RUNOFF} &= (350 \text{ acre-ft/yr})(3.259 \times 10^5 \text{ gal/acre-ft}) \\ &= 114 \times 10^6 \text{ gal/yr} \end{aligned}$$

It is to be noted that a large fraction of the moisture, particularly that which comes in the form of snowfall, will result in infiltration rather than runoff.

Reference

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 32-59 and 234-243.

⑩ Particulate Emissions From Retort and Retorted Shale Treatment Facility

The quantity of particulates released to the atmosphere after controls is 460 tons/yr.

Particulate emissions will be controlled by installing dust collection equipment at the process emission point sources. Fabric filters may be used at all process point sources except for the shale moisturizers, where Venturi scrubbers may be used. These scrubbers may be used because the shale moisturizer exit gases have a high relative humidity, rendering baghouse filters ineffective. Thus, particulate emissions from the retort feed, discharge, and shale moisturizer, on a daily basis, are[1]

Particulates = (emissions from retort feed) + (emissions from retort discharge) + (emissions from moisturizer)

= [(emission factor for retort feed)(shale feed rate)(1-control efficiency) + (emission factor for retort discharge)(shale feed rate)(retorted shale factor)(1-control efficiency) + (emission factor for shale moisturizer)(shale feed rate)(retorted shale factor)(1-control efficiency)]/(lb/ton)

= [(2.8 lb/ton)(88 x 10^3 tons/day)(1-0.997) + (4.4 lb/ton)(88 x 10^3 tons/day)(0.81 ton retorted shale/ton mined shale)(1-0.997) + (1.7 lb/ton)(88 x 10^3 tons/day)(0.81 ton retorted shale/ton mined shale)(1-0.99)]/(2 x 10^3 lb/ton)

= 1.4 tons/day

On a yearly basis,

Particulates = (1.4 tons/day)(0.9 capacity factor)(365 days/yr)

= 460 tons/yr

Reference

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 179 and 191-194.

⑪ Carbon Dioxide Emissions From the Retort

During the retorting of oil shale, 4.1 x 10^6 ton/yr of carbon dioxide will be released to the atmosphere.

The Green River shale that is used in the Paraho retort contains mineral carbonates, which when combusted, produce carbon dioxide (CO_2) emissions.[1] If it is assumed that 285 lb of carbon dioxide are released per ton of shale retorted,[2] then on a daily basis,

$$\begin{aligned} CO_2 &= (CO_2 \text{ emission factor})(\text{shale feed rate})/(\text{lb/ton}) \\ &= (285 \text{ lb/ton})(88 \times 10^3 \text{ tons/day})/(2 \times 10^3 \text{ lb/ton}) \\ &= 12.5 \times 10^3 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} CO_2 &= (12.5 \times 10^3 \text{ tons/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 4.1 \times 10^6 \text{ tons/yr} \end{aligned}$$

Note that if all of the carbonates are reduced to CO_2 during the combustion process (which will occur if the temperature is high enough), the amount of CO_2 formed will be higher by a factor of two to three.[3] Thus, the Paraho process is faced with options of either exceeding a temperature of 900°F to oxidize carbonates to CO_2 (thereby increasing air emissions) or operating at a lower temperature to retain carbonates in the retorted shale thereby adding to the potential leaching problem.

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, p. 114.
2. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, Office of Health and Environmental Research, "Carbon Dioxide Emissions from Synthetic Fuels Energy Sources," August 8, 1979, Appendix B.
3. Personal communication, Glenn Miller (U.S. Geological Survey, Grand Junction, Colorado), September 1980.

⑫ Retort Gas and Shale Oil Separation

After the oil shale is retorted, shale oil vapors are removed from the product gas by electrostatic precipitators. The product oil produced (less 1.5 percent associated water) is 55.5 x 10^3 bbl/day. The water condensate available to meet the water needs of the Paraho process is 125 x 10^6 gal/yr.

The product gas from the retort consists of a mixture of shale oil vapors; particulate matter; light hydrocarbon gases; water; and noncondensable gases such as nitrogen, hydrogen, carbon dioxide, ammonia, and hydrogen sulfide. In the Paraho process, gases leave the retort at a temperature of approximately 150°F. At this temperature, aqueous condensation will occur; therefore, the oil can be separated from the retort gas relatively free of water. The oil aerosol is removed from the retort gases by passing through electrostatic separators. This so-called "dry" oil contains approximately 1.5 percent water and is upgraded by hydrogenation to syncrude. The yield of product shale oil is about 0.64 bbl per ton mined.[1]

Barrels of "dry" product oil per day = (shale feed rate)(shale oil factor)
= (88 x 10^3 tons/day)(0.64 bbl/ton)
= 56.3 x 10^3 bbl/day

Barrels of product oil less water = ("dry" product oil)(1-water content)
= (56.3 x 10^3 bbl/day)(1-0.015)
= 55.5 x 10^3 bbl/day

Water contained in product oil = ("dry" product oil)(water content)(gal/bbl)
= (56.3 x 10^3 bbl/day)(0.015)(42 gal/bbl)
= 35.5 x 10^3 gal/day

Note that syncrude oil production is about 10 percent less than the product shale oil production.

After the product oil is removed from the retort gas, approximately 67 percent of the retort gas is recycled to the retort and burned, and the remaining 33 percent is cooled and treated to remove ammonia (NH_3) and hydrogen sulfide (H_2S). Water is formed during retorting of the oil shale, partly by combustion of hydrogen and oxygen and partly due to the release of combined and free moisture in the shale. This water is condensed and goes to the water treatment and recycling facility. The amount of water produced by oil shale retorting and available as process condensate is[1]

$$
\begin{aligned}
W_{\text{CONDENSATE}} &= W_{\text{PRODUCED}} - W_{\text{PRODUCT OIL}} - W_{\text{PRODUCT GAS}} \\
&= (0.66 \times 10^6 \text{ gal/day}) - (0.036 \times 10^6 \text{ gal/day}) - (0.237 \times 10^6 \text{ gal/day}) \\
&= 0.39 \times 10^6 \text{ gal/day}
\end{aligned}
$$

On a yearly basis,

$$
\begin{aligned}
W_{\text{CONDENSATE}} &= (0.39 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\
&= 125 \times 10^6 \text{ gal/yr}
\end{aligned}
$$

Reference

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 32-59 and 234-243.

⑬ Retort Offgas

About 67 percent of the product gas is recycled to the retort and used to generate process heat; 33 percent of the product gas is scrubbed for NH_3 and H_2S removal and then used as fuel to produce in-plant power requirements.

After the retort offgas has had water and shale oil removed, it has a heating value of approximately 100 Btu/scf. The total amount of gas produced during the retorting process is about 22 x 10^3 scf/ton of shale. About two-thirds of this gas (14.8 x 10^3 scf/ton) is mixed with air and recycled to the combustion and retorting zones of the retort to provide process heat, and the remaining one-third (7.2 x 10^3 scf/ton) is used as in-plant fuel for power generation.[1] The total heat content of the gas used to generate electrical power is given by

$$\begin{aligned}\text{Total heat content} &= (\text{gas heat content})(\text{total amount of gas used})\\ &= (100\ \text{Btu/scf})(7.2 \times 10^3\ \text{scf/ton})(88 \times 10^3\ \text{tons/day})\\ &= 63.4 \times 10^9\ \text{Btu/day}\end{aligned}$$

To determine the net power that this amount of energy is capable of producing, the net station heat rate (i.e., the amount of heat that must be delivered to the boiler to obtain 1 kWh of electricity) must be known. A typical value for this variable is 9750 Btu/kWh (which corresponds to an overall efficiency of 35 percent) and is assumed. Therefore,

$$\begin{aligned}\text{Net power delivered} &= \frac{(\text{total heat content})}{(\text{net station heat rate})}\\ &= \frac{(63.4 \times 10^9\ \text{Btu/day})}{(9.750 \times 10^3\ \text{Btu/kWh})(24\ \text{hr/day})(10^3\ \text{kW/MWe})}\\ &= 270\ \text{MWe}\end{aligned}$$

However, because only 95 MWe of power will actually be required at the Paraho facility, 175 MWe will be exportable to the grid.[2]

As discussed in later sections, the retort gas cannot be fed directly into the boiler because it has high concentrations of ammonia (NH_3) and hydrogen sulfide (H_2S). Upon combustion, the ammonia and hydrogen sulfide would be oxidized to NO_x and SO_2 producing unacceptable residual emissions. Thus, NH_3 and H_2S are removed from the product gas prior to combustion in the steam boiler.

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 39 and 40.

2. J.M. McKee and S.K. Kunchal, "Energy and Water Requirements for an Oil Shale Plant Based on Paraho Processes," Quarterly of the Colorado School of Mines, Vol. 71, No. 4, October, 1976, pp. 46-64.

⑭ Ammonia Removal From Retort Gas

The Phosam-W process is used to scrub NH_3 from the retort gas to reduce NO_x emissions to the atmosphere to acceptable levels.

As a result of the reducing atmosphere found in the retort, very little NO_x is produced; the nitrogen that is volatilized forms NH_3 instead.[1,2] To ensure that the NO_x emissions resulting from the combustion of the product gas in the gas turbine do not exceed New Source Performance Standards (NSPS), the amount of NH_3 present in the gas has to be determined.

The product gas has a molecular weight of 28.43, and the NH_3 component of this gas is 0.7 percent (dry volume).[2] Thus the NH_3 mole fraction is given by

$$\begin{aligned}\text{Mole fraction} &= (\text{dry volume percent})(\text{molecular weight})/(\text{product gas molecular weight})\\ &= (7 \times 10^{-3})(17)/(28.43)\\ &= 4.2 \times 10^{-3}\end{aligned}$$

The total amount of retort gas sent to the boiler is

$$\begin{aligned}\text{Boiler gas (volume)} &= (7.2 \times 10^{3}\ \text{scf/ton})(\text{shale feed rate})\\ &= (7.2 \times 10^{3}\ \text{scf/ton})(88 \times 10^{3}\ \text{tons/day})\\ &= 0.63 \times 10^{9}\ \text{scf/day}\end{aligned}$$

This quantity of retort gas, in terms of moles, is given by

$$\begin{aligned}\text{Boiler gas (moles)} &= (\text{boiler gas (volume)})/(\text{gaseous volume of 1 mole at standard temperature and pressure})\\ &= \frac{0.63 \times 10^{9}\ \text{scf/day}}{0.79\ \text{scf/mole}}\\ &= 0.8 \times 10^{9}\ \text{moles/day}\end{aligned}$$

Now, because each mole of this gas weighs 28.43 g, the amount of NH_3 present in the retort gas is

$$\begin{aligned} NH_3 &= \text{(boiler gas (moles))(molecular weight)(mole fraction)} \\ &= (0.8 \times 10^9 \text{ mole/day})(28.43 \text{ g/mole})(4.2 \times 10^{-3})(2.205 \times 10^{-3} \text{ lb/g}) \\ &= 0.21 \times 10^6 \text{ lb/day} \end{aligned}$$

Thus, if the retort gas is combusted without NH_3 removal, assuming complete conversion to NO_x and neglecting thermal NO_x formation, the amount of NO_x produced per thermal input is given by

$$\begin{aligned} NO_x \text{ emission} &= (NH_3 \text{ quantity})/(\text{total heat content of product gas}) \\ &= (0.21 \times 10^6 \text{ lb/day})/(63.4 \times 10^9 \text{ Btu/day}) \\ &= 3.31 \text{ lb}/10^6 \text{ Btu} \end{aligned}$$

This value exceeds the NSPS for NO_x (see item ⑯, Flue Gas), and the NH_3 must therefore be removed prior to entering the boiler.

A closed water scrubbing system, the Phosam-W process, will be used to reduce NH_3 concentrations.[1] The retort gas enters the ammonia absorber at approximately 150°F. Because downstream equipment (the Stretford units) require 95°F gas temperature and the lower temperatures increase the solubility of NH_3 in water, the retort gas is first cooled by direct contact with cold water.[2] The absorption tower used in the Phosam-W process is a combination of a cooler and absorber and has a potential 99.5 percent removal efficiency.[3] The retort gas is cooled in the lower section of the tower and NH_3 is absorbed in the upper section by countercurrent contact with phosphate solution (without ammonia) entering at the top. The NH_3 is stripped from this solution by steam. Distillation in an ammonia fractionater produces high purity anhydrous NH_3 vapor, which is captured and can be sold.[3] Note that due to the relatively low temperature, some organic compounds will condense during passage through the Phosam-W system and the stream will therefore have to be suitably treated.

References

1. U.S. Department of Energy/Assistant Secretary for Fossil Energy, "Draft EIS, Paraho Research Project at the Anvil Points Oil Shale Facility," June 9, 1980, p. 5.13.

2. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 41, 121, 195-201, and 234-243.

3. DRAVO Corp., Handbook of Gasifiers and Gas Treatment Systems, for Department of Energy/Assistant Secretary for Fossil Energy under Contract No. E(4918)-1772, Fossil Energy Report No. 177-211, February 1976, pp. 142-144.

⑮ Hydrogen Sulfide Removal From Retort Gas

The Stretford process is used to scrub H_2S from the retort gas to minimize SO_2 emissions to the ambient atmosphere.

Based on the reasoning used in item ⑭, Ammonia Removal From Retort Gas, it can be shown that the amount of H_2S present in the retort gas is[1]

$$
\begin{aligned}
H_2S &= \text{(boiler gas (moles))(molecular weight)(mole fraction)} \\
&= (0.8 \times 10^9 \text{ moles/day})(28.43 \text{ g/mole})(3.6 \times 10^{-3})(2.205 \times 10^{-3} \text{ lb/g}) \\
&= 0.18 \times 10^6 \text{ lb/day}
\end{aligned}
$$

If the retort gas is combusted without H_2S removal and assuming complete conversion to SO_2, the amount of SO_2 produced (per thermal input) is given by

$$
\begin{aligned}
SO_2 &= (H_2S \text{ quantity})/(\text{total heat content of product gas}) \\
&= (0.18 \times 10^6 \text{ lb/day})/(63.4 \times 10^9 \text{ Btu/day}) \\
&= 2.84 \text{ lb}/10^6 \text{ Btu}
\end{aligned}
$$

This value exceeds the NSPS for SO_2 (see item ⑯, Flue Gas) and the H_2S must therefore be removed prior to entering the boiler.

The Stretford process, with a potential removal efficiency in excess of 9 percent, may be used to remove H_2S from the retort gas.[2,3] Actual removal efficiency for H_2S is discussed in item ⑯, Flue Gas. Hydrogen sulfide is dissolved in a mixture of sodium carbonate and sodium bicarbonate, is weakly ionized, and forms sodium hydrosulfide. The sodium hydrosulfide is oxidized, producing sulfur of high purity, which is captured and can be sold. If actual operating experience shows that a relatively large fraction of sulfur-containing species, other than H_2S, are present, then additional sulfur removal techniques may have to be employed.

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 40, 121, 206, and 207.

2. U.S. Department of Energy/Assistant Secretary for Fossil Energy, "Draft EIS, Paraho Research Project at the Anvil Points Oil Shale Facility," June 9, 1980, p. 5.14.

3. U.S. Environmental Protection Agency Oil Shale Work Group, "Pollution Control Guidance for Oil Shale Development, Revised Draft Report," U.S. EPA/ORD/IERL-Ci, July 1979, pp. 4-10 and 11.

(16) Flue Gas

The pollutants that are part of the flue gas emitted to the atmosphere past controls are as follows:

Sulfur dioxide	*2.9×10^3 tons/yr*
Nitrogen oxides	*2.1×10^3 tons/yr*
Hydrocarbons	*0.1×10^3 tons/yr*
Carbon monoxide	*1.8×10^3 tons/yr*
Carbon dioxide	*1.1×10^6 tons/yr*

Sulfur Dioxide

The amount of SO_2 emitted to the atmosphere is 0.28 lb/10^6 Btu. The current New Source Performance Standards for SO_2 emissions are summarized below.[1]

Uncontrolled Emissions (lb $SO_2/10^6$ Btu)	Percent Reduction Needed	Controlled Emissions (lb $SO_2/10^6$ Btu)
>8	>90	0.8 (maximum)
8 to 2	90	0.8 → 0.2
2 to 0.2	90 → zero	0.2 (constant)

Basically, for gaseous fuels burned in a boiler with uncontrolled emissions exceeding 8 lb $SO_2/10^6$ Btu, SO_2 reductions exceeding 90 percent would be required to limit emissions to a maximum of 0.8 lb $SO_2/10^6$ Btu. For gaseous fuels whose uncontrolled emissions range from 8 to 2 lb/10^6 Btu, a constant 90-percent removal is required, resulting in controlled emissions ranging from 0.8 lb $SO_2/10^6$ Btu to 0.2 lb/10^6 Btu. For gaseous fuels with sulfur contents that would emit 2 to 0.2 lb $SO_2/10^6$ Btu, a variable removal rate between 90 and zero percent is required to achieve a constant 0.2 lb $SO_2/10^6$ Btu. For example, at 2 lb $SO_2/10^6$ Btu, 90-percent removal is required; at 0.2 lb $SO_2/10^6$ Btu, zero percent is required; and at 1 lb $SO_2/10^6$ Btu, 80 percent is needed. In all cases, it should be noted that the controlled emissions are 0.2 lb/10^6 Btu.

Uncontrolled SO_2 emissions from the retort gas would yield 2.84 lb/10^6 Btu. Hence, the Stretford scrubbers have to operate at 90-percent H_2S removal efficiency. On a yearly basis, controlling SO_2 to 0.28 lb/10^6 Btu gives (at 90-percent capacity factor),

$$\begin{aligned} SO_2 &= (0.28\ \text{lb}/10^6\ \text{Btu})(63.4 \times 10^9\ \text{Btu/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 5.8 \times 10^6\ \text{lb/yr} \\ &= 2.9 \times 10^3\ \text{tons/yr} \end{aligned}$$

Nitrogen Oxides

The current New Source Performance Standards for NO_x is[1] 0.2 lb/10^6 Btu. The amount of NO_x emitted to the ambient atmosphere is 0.2 lb/10^6 Btu.

The general way of achieving compliance with NO_x emissions regulations is to employ combustion modification techniques.[2,3] The boiler manufacturer usually includes in his performance guarantee the provision that emissions of nitrogen oxides shall be less than 0.2 lb/10^6 Btu.[4] Emissions of oxides of nitrogen are limited by low flame and furnace temperatures, by short residence time of the gases at high temperatures, and by reduced amounts of excess air present in the combustion zone.

On a yearly basis, controlling NO_x to 0.2 lb/10^6 Btu gives (at 90-percent capacity factor),

$$\begin{aligned} NO_x &= (0.2\ \text{lb}/10^6\ \text{Btu})(63.4 \times 10^9\ \text{Btu/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 4.2 \times 10^6\ \text{lb/yr} \\ &= 2.1 \times 10^3\ \text{tons/yr} \end{aligned}$$

Carbon Monoxide and Hydrocarbons

There are no New Source Performance Standards for carbon monoxide or hydrocarbons. The amounts of CO and HC emitted to the atmosphere are 5.4 tons/day and 0.3 ton/day, respectively.

The emission factors for CO and HC are 17 lb/10^6 Btu fuel burned and 1 lb/10^6 Btu fuel burned, respectively.[5] These emission factors are for natural gas combustion and will probably give values that are slightly lower than will be found in practice. Hence, the daily emissions of these pollutants are given by

$$\text{CO, HC} = (\text{emission factor})(\text{retort gas feed rate})$$

For the typical plant,

$$\begin{aligned} \text{CO} &= (17\ \text{lb}/10^6\ \text{ft}^3)(7.2 \times 10^3\ \text{ft}^3/\text{ton})(88 \times 10^3\ \text{tons/day})/(2 \times 10^3\ \text{lb/ton}) \\ &= 5.4\ \text{tons/day} \end{aligned}$$

$$\begin{aligned} \text{HC} &= (1\ \text{lb}/10^6\ \text{ft}^3)(7.2 \times 10^3\ \text{ft}^3/\text{ton})(88 \times 10^3\ \text{tons/day})/(2 \times 10^3\ \text{lb/ton}) \\ &= 0.3\ \text{ton/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{CO} &= (5.4\ \text{tons/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 1.8 \times 10^3\ \text{tons/yr} \end{aligned}$$

$$\begin{aligned} \text{HC} &= (0.3\ \text{ton/yr})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 0.1 \times 10^3\ \text{tons/yr} \end{aligned}$$

An indication of the completeness of a combustion process is the concentration of carbon monoxide (and, to a lesser extent, hydrocarbon concentration). Because utility boilers operate at high efficiencies, negligible emissions of carbon monoxide and hydrocarbons result. Careful monitoring of excess air and temperature in the boiler ensures that the emissions of these pollutants are low.

Carbon Dioxide

The amount of CO_2 emitted to the atmosphere is 3.5×10^3 tons/day.

During the combustion of retort gas, 0.11 lb CO_2 is emitted to the atmosphere for every 10^3 Btu generated.[6] Hence,

$$\boxed{CO_2 = \text{(emission factor)(retort gas feed rate)}}$$

For the Paraho plant,

$$\begin{aligned} CO_2 &= (0.11\ \text{lb}/10^3\ \text{Btu})(63.4 \times 10^9\ \text{Btu/day})/(2 \times 10^3\ \text{lb/ton}) \\ &= 3.5 \times 10^3\ \text{tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} CO_2 &= (3.5 \times 10^3\ \text{tons/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 1.1 \times 10^6\ \text{tons/yr} \end{aligned}$$

References

1. Federal Register, Vol. 44, No. 113, 40 CFR Part 60, "New Source Performance Standards; Electric Utility Steam Generating Units," June 11, 1979.

2. J. Ando, "NO_x Abatement for Stationary Sources in Japan," EPA-600/7-79-205, August 1979.

3. National Academy of Sciences, "Air Quality and Stationary Source Emission Control," prepared for the Committee on Public Works, U.S. Senate, Serial No. 94-4, 1975.

4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978.

5. U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," 2nd edition, EPA AP-42, 1975, pp. 1.4.1, 2.

6. U.S. Department of Energy, "CO_2 Emissions from Synthetic Fuels Energy Sources," August 8, 1979, p. 2, Table 1.

⑰ Cooling Tower Blowdown

Cooling tower blowdown is 329 x 10^6 gal/yr and is used for dust control and spent shale moistening and disposal. Dust control requires 240 x 10^6 gal/yr, which leaves 89 x 10^6 gal/yr for spent shale disposal, supplementing the water recycled from the water treatment and recycling facility.

Blowdown water typically contains biocides (e.g., chlorine) added for marine and biological growth control, corrosion inhibitors, a high concentration of total dissolved solids, and excess heat. Without treatment, the blowdown water is not suitable for high quality uses within the plant. Fortunately, sufficient low quality water requirements exist so that the entire cooling tower blowdown can be utilized within the plant without additional treatment. Consequently, the cooling tower blowdown is used for dust control and for spent shale moistening and disposal.

The cooling tower blowdown for a Paraho plant producing 50,000 bbl syncrude per day is[1]

$$
\begin{aligned}
W_{BLOWDOWN} &= (11.5 \text{ gal/ton shale})(88 \times 10^3 \text{ tons/day}) \\
&= 1.0 \times 10^6 \text{ gal/day}
\end{aligned}
$$

On a yearly basis,

$$
\begin{aligned}
W_{BLOWDOWN} &= (1.0 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\
&= 329 \times 10^6 \text{ gal/yr}
\end{aligned}
$$

Blowdown water, which is generally of low quality, is used for dust and particulate control at the mine and at the crushing and screening operation as well as for spent shale disposal and handling. Of the 1.0 x 10^6 gal/day of blowdown water available, 0.46 x 10^6 gal/day are used for dust control at the mine, 0.27 x 10^6 gal/day are used for dust control at the crushing and screening operation, and 0.27 x 10^6 gal/day are available for spent shale disposal.[1]

On a yearly basis,

$$
\begin{aligned}
W_{DUST\ (MINE)} &= (0.46 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\
&= 151 \times 10^6 \text{ gal/yr}
\end{aligned}
$$

$$
\begin{aligned}
W_{DUST\ (CRUSHING)} &= (0.27 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\
&= 89 \times 10^6 \text{ gal/yr}
\end{aligned}
$$

$$
\begin{aligned}
W_{SHALE} &= (0.27 \times 10^6 \text{ gal/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\
&= 89 \times 10^6 \text{ gal/yr}
\end{aligned}
$$

Reference

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 32-59 and 234-243.

⑱ Evaporative and Drift Losses From Wet Cooling Towers

Evaporative and drift losses from the cooling towers into the atmosphere are approximately 445 x 10^6 gal/yr for a typical Paraho oil shale plant producing 50,000 barrels syncrude per day.

The above values are based on the assumption that the retort oil gas mixture leaves the retort at a sufficiently high temperature such that the water remains in the vapor phase until after the oil has been removed. After the product oil has been removed, approximately two-thirds of the retort gases are recycled to the retort and burned. The remaining gases are cooled by water scrubbing to remove H_2S and NH_3 and sent to the steam boiler for use in generating electrical power. The evaporative losses therefore represent the total plant cooling requirements and include the cooling requirements for the retort gases,[1] the steam turbine,[2] and the Phosam W process[1] used to recover NH_3 from the retort gases and from the shale oil upgrading process.

The water requirement due to cooling tower evaporation is given by[1]

$$W_{EVAP}\text{, gal/day} = (15.3\ \text{gal/ton shale})(\text{shale feed rate})$$

For the 50,000-barrel-per-day syncrude plant

$$\begin{aligned} W_{EVAP} &= (15.3\ \text{gal/ton shale})(88 \times 10^3\ \text{tons/day}) \\ &= 1.35 \times 10^6\ \text{gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{EVAP}\text{, gal/yr} &= (1.35 \times 10^6\ \text{gal/day})(0.9\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 445 \times 10^6\ \text{gal/yr} \end{aligned}$$

The above values include a drift loss of about 0.5 percent.[1]

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 32-59 and 234-243.

2. J. McKee and S.K. Kunchal, "Energy and Water Requirements for an Oil Shale Plant Based on the Paraho Processes," Quarterly of the Colordao School of Mines, October 1976, pp. 49-64.

⑲ Makeup Water

Makeup water from local, available sources totaling 1.184 x 10^9 gal/yr are needed to supplement the reused effluents of the Paraho plant.

The Paraho process described herein is assumed to operate on the premise that all effluent streams are reused and that no wastewater is discharged. The water treatment facility operates on the premise that not all the water used in the plant needs to be of high quality and, therefore, only that level of treatment is provided which is consistent with the intended water use. For example, the water that is used for dust control and shale disposal need not be of high quality and, therefore, process condensate or cooling tower blowdown treated only minimally is satisfactory. However, water to be used for irrigation or dust control would have to be tested for acceptance. The process condensate is treated to remove ammonia and acid gas followed by organic removal (e.g., charcoal filtration) and then is blended with water drawn from available local sources to provide some of the cooling tower makeup water. The controlled rainfall runoff from the disposal site flows to the treatment plant and is used to reduce the makeup water required from local sources. The treatment facility also includes a biological oxidation plant for the treatment of sanitary wastes associated with the water service for the employees at the plant. The digested sludge is disposed of at the spent shale site and the effluent is used for dust control or spent shale disposal.[1] The water services requirements[2] for a plant employing 1260 people (permanent work force) is 0.0235 gal/min/person.

On a yearly basis,

$$
\begin{aligned}
W_{\substack{\text{SEWAGE}\\\text{EFFLUENT}}} &= (0.0235\ \text{gal/min/person})(1260\ \text{persons})(60\ \text{min/hr})(24\ \text{hr/day})\\
&\qquad (0.9\ \text{capacity factor})(365\ \text{days/yr})\\
&= 14 \times 10^6\ \text{gal/yr}
\end{aligned}
$$

In spite of reusing the effluent streams, insufficient water is available to meet the plant requirements (including cooling tower makeup), and makeup water drawn from available local sources is needed.

Cooling tower makeup water (W_{TOW}) is obtained by adding the water losses due to evaporation and drift (W_{EVAP}) to the cooling tower blowdown losses ($W_{BLOWDOWN}$) and subtracting the water recycled to the cooling tower from the water treatment facility ($W_{RECYCLED}$) as follows:[1]

$$W_{TOW} = W_{EVAP} + W_{BLOWDOWN} - W_{RECYCLED}$$

For the Paraho plant

$$W_{TOW} = (445 \times 10^6 \text{ gal/yr}) + (329 \times 10^6 \text{ gal/yr}) - (128 \times 10^6 \text{ gal/yr})$$
$$= 646 \times 10^6 \text{ gal/yr}$$

The cooling tower makeup water requirements will be furnished as raw makeup water drawn from available local sources and suitably pretreated. Pretreatment will include clarification, which will be required to prevent clogging and plugging of orifices such as nozzles.[1]

The amount of makeup water is given by

$$W_{WTRF} = (\text{water required by Paraho process}) - (\text{water supplied by effluents})$$

$$W_{WTRF} = W_{SYNCRUDE} + W_{RECYCLED} + W_{\substack{SHALE\\DISPOSAL}} + W_{TOW} - W_{\substack{SEWAGE\\EFFLUENT}} - W_{RUNOFF} - W_{CONDENSATE}$$

$$W_{WTRF} = (69 \times 10^6 \text{ gal/yr}) + (128 \times 10^6 \text{ gal/yr}) + (594 \times 10^6 \text{ gal/yr}) + (646 \times 10^6 \text{ gal/yr}) - (14 \times 10^6 \text{ gal/yr}) - (114 \times 10^6 \text{ gal/yr}) - (125 \times 10^6 \text{ gal/yr})$$
$$= 1.184 \times 10^9 \text{ gal/yr}$$

Sludge consisting primarily of sediment from treatment of the makeup water does not pose any serious problem and will be disposed of with the retorted shale.

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 32-59 and 234-243.

2. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, MIT Press, Cambridge, Massachusetts, 1978.

⑳ Upgrading Shale Oil to Syncrude

Prior to sending shale oil to a refinery, the nitrogen and sulfur concentrations are each reduced by about 99 percent, and arsenic concentration is reduced to parts per trillion range.

The shale oil is assumed to be upgraded onsite before it is sent to a conventional refinery because the shale oil is highly unsaturated and much of the hydrocarbon component is in heterocompounds containing reactive fragments of nitrogen and sulfur.[1-3] In addition, there is a relatively large arsenic concentration in shale oil (approximately 40 ppm).[4] (See Table 2 for the composition and properties of shale oil.) It is highly desirable to remove these elements for several reasons: nitrogen and sulfur must be removed for pollution control, sulfur compounds promote corrosion and result in poor lead susceptibility, nitrogen and arsenic poison the hydrocracking processing and reforming catalysts used in refining, and large concentrations of nitrogen adversely affect the thermal and storage stability of diesel and turbine fuels.[5,6]

Table 2. Composition and Properties of Paraho Shale Oil[4,7]

Composition	
Total Carbon	84.73 Weight %
Total Hydrocarbon	11.34 Weight %
Total Nitrogen	1.99 Weight %
Total Oxygen	1.27 Weight %
Total Sulfur	0.63 Weight %
Trace elements	0.04 Weight %

Properties	
Gravity, °API	21.2
Specific gravity @60°F	0.9267
Pour point, °F	80
Viscosity, sus @100°F	162.9

During the hydrotreatment of the shale oil, NH_3 and H_2S are formed by catalytically combining hydrogen with nitrogen and sulfur. The Phosam-W process is used to remove 99 percent of the NH_3 and the Stretford process is used to remove 99 percent of the H_2S.[8] Water supplies the hydrogen needed for hydrotreating and 1 mole of water is required to convert the sulfur compounds to H_2S and 1.5 moles of water are required to convert the nitrogen compounds to NH_3. Using the weight percentages for sulfur and nitrogen in Table 2, it can be shown that approximately 1.8 gallons of H_2O are required per barrel of shale oil (cooling load included). In addition, the

Phosam-W NH_3 removal process requires approximately 0.23 gal H_2O/lb NH_3 recovered.[4] Hence, on a daily basis, the amount of water that will be evaporated to recover the NH_3 formed in the upgrading process is given by

$$\begin{aligned}\text{Water for NH}_3\text{ removal} &= (55.6 \times 10^3 \text{ bbl/day})(42 \text{ gal/bbl})(8.34 \text{ lb/gal})(0.0199 \text{ nitrogen} \\ &\qquad \text{weight fraction})(1.21 \text{ NH}_3\text{/N weight ratio})(0.23 \text{ gal H}_2\text{O/lb NH}_3) \\ &= 108 \times 10^3 \text{ gal/day}\end{aligned}$$

Therefore, the total daily water requirement is given as

$$\begin{aligned}W_{SYNCRUDE} &= (\text{water for hydrotreating}) + (\text{water for NH}_3\text{ removal}) \\ &= (1.8 \text{ gal/bbl})(55 \times 10^3 \text{ bbl/day}) + (108 \times 10^3 \text{ gal/day}) \\ &= 0.21 \times 10^6 \text{ gal/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}W_{SYNCRUDE} &= (0.21 \times 10^6 \text{ bbl/day})(0.9 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 69 \times 10^6 \text{ gal/yr}\end{aligned}$$

Methods proposed to reduce the arsenic content of shale oil prior to further processing include using a catalytic guard bed (such as finely crushed alumina) as an absorption filter, contacting with sodium hydroxide, or noncatalytic thermal treatment.[9] In whichever method is chosen, though, arsenic concentrations will be reduced to parts per trillion range.[10]

References

1. M.T. Atwood, "The Production of Shale Oil," Chemtech, October 1973, pp. 617-621.

2. G.U. Dinneen, J.S. Ball, and H.M. Thorne, "Composition of Crude Shale Oils," Ind. Eng. Chem., Vol. 44, 1952, pp. 2632-2635.

3. U.S. Environmental Protection Agency Oil Shale Work Group, "Pollution Control Guidance for Oil Shale Development, Revised Draft Report," U.S. EPA/ORD/IERL-Ci, July 1979, pp. 7-11, 12, 13.

4. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Process," DOE/EV-0055, October 1979, pp. 41, 42, 241, 244, 375-380.

5. W.J. Barnet, J.H. Duir, R.C. Hansford, and A.J. Talleners, "External Hydrocracking to Heavy Stocks," Petrol Ref., Vol. 40, No. 4, 1961, pp. 131-136.

6. W.C. Lanning, "The Refining of Shale Oil," prepared for U.S. Department of Energy by Bartlesville Energy Research Center, BERC/IC-77/3, May 1978, pp. 1-13.

7. R.N. Heistand and R.A. Atwood, "Paraho Environmental Data, Part I, Process Characterization," DOE/EV-0086, June 1980, p. 3-1.

8. Personal communication, Dr. E. Smith (Laramie Energy Technology Center, Laramie, Wyoming), August 20, 1980.

9. R.F. Sullivan, B.E. Strangeland, H.A. Frumkin, and C.W. Samuel, "Refining Shale Oil," Preprint No. 25-78, Chevron Research Company and Chrevron U.S.A., Inc., May 10, 1978. Presented at the API Refining Department 43rd Midyear Meeting, Toronto, Ontario, Canada.

10. Personal communication, Richard Young (American Petroleum Institute, Washington, D.C.), September 4, 1980.

IV. PHYSICAL REQUIREMENTS

Compared to coal mining and other synfuel processes, relatively large amounts of land and water resources are required for an oil shale facility over its lifetime. The section on Water summarizes the requirements and uses of makeup water discussed in Section III. The section on Land discusses the land needed for plant siting and solid waste disposal.

Water

The maximum water demand estimated for the typical plant operating at 90-percent capacity factor is 1.766 x 10^9 gal/yr. Some of this water is recovered, treated in the water treatment facility, and recycled back to the plant (see Section III, item ⑲, Makeup Water). The remainder is obtained from available local water sources and is lost primarily through evaporation and drift losses in the cooling towers and dust suppression systems. The major water uses and sources of recyclable water are listed in Table 3. Using the information listed in this table, the net makeup water requirement is determined as follows:

$$\boxed{\begin{aligned} W_{NET} &= (\text{water requirements}) - (\text{recovered water for recycling}) \\ &= (1.766 \times 10^9 \text{ gal/yr}) - (582 \times 10^6 \text{ gal/yr}) \\ &= 1.184 \times 10^9 \text{ gal/yr } (= 3634 \text{ acre-ft/yr}) \end{aligned}}$$

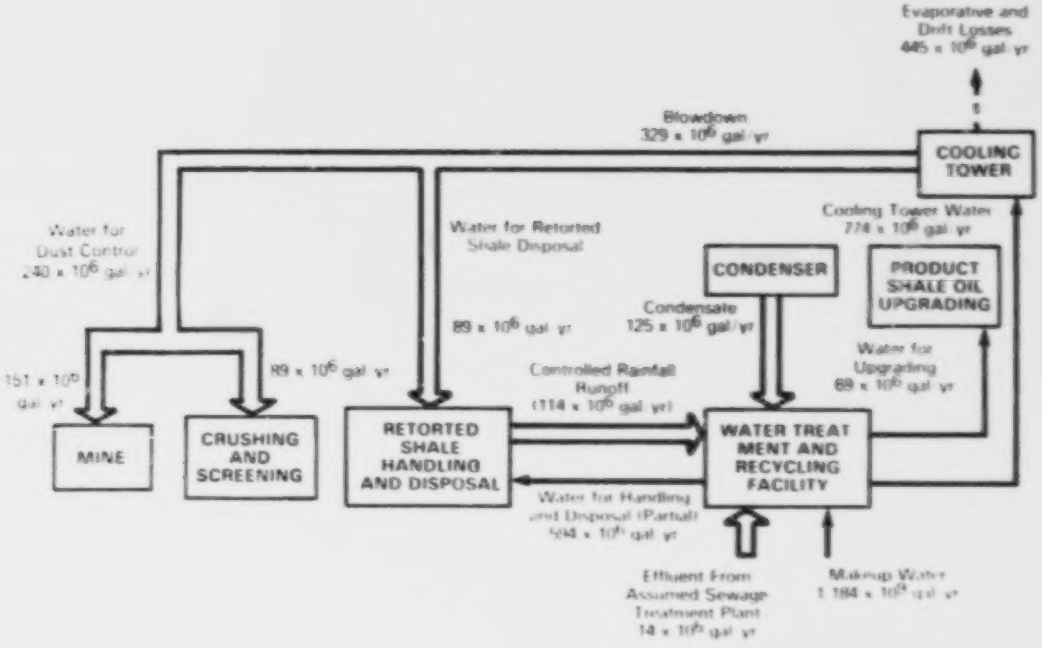
Thus, the net makeup water requirement per barrel of syncrude produced is given by

$$\boxed{\begin{aligned} \tilde{W}_{NET} &= \frac{(W_{NET})/(\text{gal/bbl})}{(\text{barrels of syncrude equivalent})} \\ &= \frac{(1.184 \times 10^9 \text{ gal/yr})/(42 \text{ gal/bbl})}{(16.4 \times 10^6 \text{ bbl/yr})} \\ &= 1.7 \text{ bbl water/bbl syncrude} \end{aligned}}$$

Note that $\tilde{W}_{NET}$ will be higher if a less efficient water recycling plant were used. As such, a water to syncrude ratio of 1.7 can be considered a lower bound estimate.

Table 3. Water Demands for and Availability From Major Paraho Plant Processes (at 90 Percent Capacity Factor)

Source	Environmental Point of Interest on Flow Chart		Estimated Quantity gal/yr	Estimated Quantity acre-ft/yr
Water Requirements				
Dust Control	⑰		240×10^6	736
Retorted Shale Handling and Disposal	⑧⑰		683×10^6	2096
Cooling Tower	⑲		774×10^6	2377
Upgrading Facility	⑳		69×10^6	212
		Total	1.766×10^9	5421
Recovered Water for Recycling				
Controlled Rainfall Runoff	⑨		114×10^6	350
Process Condensate	⑬		125×10^6	384
Effluent From Assumed Sewage Treatment Plant	⑲		14×10^6	43
Blowdown	⑰		329×10^6	1010
		Total	582×10^6	1787


Evaporative and Drift Losses 445 x 10^6 gal/yr
Blowdown 329 x 10^6 gal/yr
COOLING TOWER
Water for Dust Control 240 x 10^6 gal/yr
Water for Retorted Shale Disposal
Cooling Tower Water 774 x 10^6 gal/yr
CONDENSER
PRODUCT SHALE OIL UPGRADING
89 x 10^6 gal/yr
Condensate 125 x 10^6 gal/yr
151 x 10^6 gal/yr
89 x 10^6 gal/yr
Controlled Rainfall Runoff (114 x 10^6 gal/yr)
Water for Upgrading 69 x 10^6 gal/yr
MINE
CRUSHING AND SCREENING
RETORTED SHALE HANDLING AND DISPOSAL
WATER TREATMENT AND RECYCLING FACILITY
Water for Handling and Disposal (Partial) 594 x 10^6 gal/yr
Effluent From Assumed Sewage Treatment Plant 14 x 10^6 gal/yr
Makeup Water 1.184 x 10^9 gal/yr

Land

An oil shale facility will require land for the permanent disposal of retorted shale, mine development (surface portion), basic site facilities (shale processing, retorting, upgrading, etc.), and offsite facilities (access roads, utility lines, etc.).

The actual land requirements will vary from site to site. The table below was developed using the shale disposal requirement developed in item ⑧, Water Requirements for Retorted Shale and Sludge Moistening and Disposal, and the estimates from environmental impact statements.[1,2]

	Land Requirements (acres)
Permanent disposal	1080
Mine development (surface portion)	10
Basic site facilities	140
Offsite facilities	725
	1955

Land Affected by Mining

A large underground volume of land will be directly affected by oil shale mining. Using a raw shale density of 140 lb/ft^3, it can be shown that the daily volume of shale mined, taking into consideration 70 percent ore recovery efficiency, is 1.86×10^6 ft^3/day. Over the 25-year plant lifetime, the total volume is given by

$$\begin{aligned} V_{SHALE} &= (1.86 \times 10^6\ ft^3/day)(0.9\ \text{capacity factor})(365\ days/yr)(25\ yr) \\ &= 15.28 \times 10^9\ ft^3 \end{aligned}$$

If it is assumed that the room height is 60 ft and that only one room level is mined, a conservative estimate of the horizonal cross sectional area of land affected by mining is given by

$$\begin{aligned} A &= V_{SHALE}/60\ ft \\ &= (15.28 \times 10^9\ ft^3)/60\ ft \\ &= 0.25 \times 10^9\ ft^2 \end{aligned}$$

In terms of acres,

$$A = (0.25 \times 10^9 \text{ ft}^2)(1 \text{ acre}/43.56 \times 10^3 \text{ ft}^2)$$
$$= 5.74 \times 10^3 \text{ acres}$$

Note that the area of land affected by mining depends on many factors such as site location, grade of shale, thickness of shale resource, method of retorted shale disposal.

References

1. U.S. Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts from Oil Shale Developments, EPA-600/7-77-069, July 1977.

2. U.S. Department of the Interior, Final Environmental Statement for the Prototype Oil Shale Leasing Program, 1973.

V. PERSONNEL

The number of people required to construct and operate a 50×10^3 bbl/day Paraho process oil shale facility will vary, depending on factors such as the duration of construction and the operating philosophy of the owners. Consequently, published personnel estimates cover a wide range. It is estimated that peak construction employment projections may range from 1300 to 3900 people and permanent employment projections may range from 1000 to 1425. One mid-range projection has been chosen as representative: 2300 persons for peak construction force and 1260 persons for the permanent force.[1,2] Note that these are generic figures for any 50×10^3 bbl/day oil shale facility.

References

1. Colorado Department of Natural Resources, "Upper Colorado River Region Section 13(a) Assessment: Interim Progress Report to the Steering Committee and U.S. Water Resources Council," October 1978.

2. U.S. Department of Energy/Assistant Secretary for Environment/Pacific Northwest Laboratory, "Preliminary Draft: Final Report on Western Oil Shale Development: A Technology Assessment," September 1980, pp. L.1-L.89.

VI. OCCUPATIONAL SAFETY AND HEALTH

The estimated occupational safety hazards associated with oil shale mining and processing (extrapolated from other industry data) are shown in the following table:[1]

	Frequency Per Worker Per Year	
	Deaths	Injuries
Underground mining	0.0014	0.062
Surface retorting	0.0004	0.045

For the work force of 1260 employees, and an estimated proportion of miners to other workers[2] (743 miners/517 workers), the estimated deaths and injuries (extrapolated from other industry data) for one 50,000-barrel-per-day facility become

	Deaths Per Year	Injuries Per Year
Underground mining	1.04	46.1
Surface retorting	0.21	23.3

With respect to occupational health, the work force will be exposed to an environment largely uncharacterized. Workers may be exposed to a complex spectrum of potentially toxic or carcinogenic dusts, vapors, and gases.[3] Additional research and development will be required to assess the biological effects of these materials and to develop controls for worker protection. Note that the figures above are generic for any 50×10^3 bbl/day oil shale facility.

References

1. U.S. Environmental Protection Agency, "Energy from the West, Impact Analysis Report, Volume I: Introduction and Summary," EPA-600/7-79-082a, March 1979, p. 140.

2. U.S. Environmental Protection Agency, "Energy from the West, Energy Resource Development Systems Report, Volume III: Oil Shale," EPA-600/7-79-060c, March 1979, p. 51.

3. U.S. Department of Energy, Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis, DOE/EV-0087, June 1980, p. 3-4ff.

APPENDIX A.
THE PARAHO RETORTING PROCESS (DIRECT MODE)

The modular Paraho retorts consist of refractory-lined, mild steel cylindrical shells. (The optimum module design for an 18×10^3 ton/day oil shale retort is currently being investigated.[1]) Raw shale is fed into the top of the retort and passes downward by gravity successively through the following zones (see Figure A-1):

- Mist Formation Zone: As the gas stream is cooled by the descending shale, oil vapors condense into a stable fog entrained by the now cooled gas.
- Retorting Zone: The preheated shale from the mist formation zone is heated further by gaseous products of combustion from below. The kerogen in the shale decomposes to evolve oil vapors and gas and to leave a carbonaceous residue in the retorted shale particles.
- Combustion Zone: This zone extends in the region of the top and middle distributors which inject and distribute an oxygen-containing gas mixture over the cross-section of the shale bed. The carbonaceous residue of the retorted shale along with some of the gas serve as the fuel in this combustion zone.
- Retorted Shale Cooling Zone: This zone has the principal function for recovering some of the sensible heat in the retorted shale. This conserved heat reduces overall process heat requirements and preheats recycle gas entering the combustion zone.

The retorted shale is discharged through a grate that controls the downward velocity and maintains even flow across the grate.[2]

The products of retorting are gases, oil, and coke. Carbon residue is dispersed within the shale and burned in the retort to supply the principal fuel for process heating. The gas produced has a low heating value (approximately 100 Btu/scf) because retort gases are diluted by products of combustion. This cool gas is recycled to the grate to cool the retorted shale to about 310°F and is also mixed with the air entering two levels of distributors, diluting it. Only sufficient air is allowed to enter the retort to maintain the desired temperature profile. Recycled gas flows and products of combustion are controlled to provide enough hot gases to retort the shale in the zone above the top distributor. Oil vapors and gas ascending from the retorting zone through the descending fresh shale preheats the shale and the oil condenses into small mist droplets near the top of the shale bed. Oil mist, entrained in the gases, is removed from the bed at about 150°F and transported to an oil mist, gas separator for oil recovery. The crude shale oil is upgraded and the syncrude product is sent to a refinery. About two-thirds of the gas (14,800 scf/ton of shale) is recycled to the retort and the remainder (7200 scf/ton of shale) is piped away to generate power for use in the plant.[3,4]

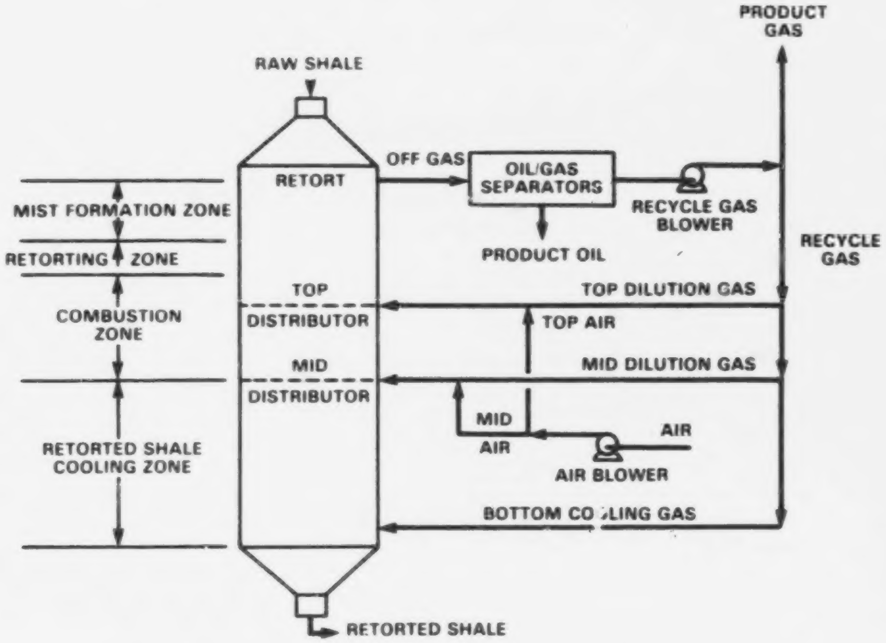

PRODUCT GAS
RAW SHALE
OFF GAS
OIL/GAS SEPARATORS
RETORT
RECYCLE GAS BLOWER
MIST FORMATION ZONE
RECYCLE GAS
RETORTING ZONE
PRODUCT OIL
TOP
TOP DILUTION GAS
COMBUSTION ZONE
DISTRIBUTOR
TOP AIR
MID
MID DILUTION GAS
DISTRIBUTOR
MID
AIR
AIR
RETORTED SHALE COOLING ZONE
AIR BLOWER
BOTTOM COOLING GAS
RETORTED SHALE

Figure A-1. Paraho Direct Heat Mode[2]

References

1. R.C. Porter, "DOE Tells Superior, Paraho to Move Ahead With Oil Shale Designs," DOE News, R-80-115, June 13, 1980.

2. R.N. Heistand and K.L. Richardson, "Paraho Environmental Data, Part I, Process Characterization," DOE/EV-0086, June 1980, pp. 1.1-1.3.

3. J.B. Jones, Jr., "Paraho Oil Shale Retort," Quarterly of the Colorado School of Mines, Proceedings of the Ninth Oil Shale Symposium, Vol. 71, October 1976, pp. 39-48.

4. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979, pp. 39-43.

APPENDIX B.
ENVIRONMENTAL CONTROL COSTS

In 1979, the Department of Energy Office of Environment published the results of an extensive study of oil shale environmental control costs.[1] The study established a range of costs based on two possible sets of technical approaches meeting various environmental control requirements. The lower end of the range results from a scenario based on the assumption that regulations would not be unusually or unreasonably restrictive. The upper end of the range reflects a more conservative approach in the selection of basic technical and economic assumptions. The results for the Paraho process are

Range of Environmental Control Costs
Per Barrel of Syncrude Equivalent
(1979 dollars)

Low	High
$0.90	$1.70

Note that neither of these estimates include consideration of new regulations, such as the Resource Conservation and Recovery Act and anticipated industrial hygiene regulations.

Reference

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Impacts, Environmental Control Costs for Oil Shale Processes, DOE/EV-0055, October 1979, Overview Section, p. 5.

APPENDIX C.
METHODS FOR MINING OIL SHALE

Green River oil shale deposits are amenable to either surface mining (open pit or strip) or to underground mining methods (such as room and pillar) depending on various factors such as accessibility, overburden thickness, and presence of groundwater in the mining zone.[1] Surface mining is economically attractive for large, low-grade ore deposits because it permits high recovery of the resource and allows sufficient space for very large and efficient mining equipment. An open pit mine could recover almost 90 percent of the oil shale in a very thick deposit. Strip mining could provide even higher recoveries. In contrast, underground mining would recover less than 70 percent.[1,2]

Open pit mining involves excavating the overlying waste rock to expose the oil shale resource below. The oil shale and waste rock are "benched" down to a depth dictated by the economic limits or cutoff grade of the pit.[1] In strip mining, overburden is removed with a dragline -- a massive type of scraper shovel. When the dragline has filled its scoop, it pivots and dumps the burden into an adjacent mined-out area. One difference between open pit and strip mines is that in strip mining, the burden is simply cast into a nearby area; in open pit, it must be moved far from the minesite to prevent interfering with the development of the pit.[2]

Many underground mining procedures have been proposed for oil shale deposits, but to date only room-and-pillar mining has been tested at any significant scale.[1] In the Piceance Creek basin, nearly 80 percent of the oil shale resource is confined to the deposits in the deep central part of the basin. For this reason, underground mining systems with high volume and low cost will probably be used to efficiently mine the thick oil shale resource, unless the entire basin were to be mined as one grand-scale open pit. Room and pillar mining was therefore chosen and assumed to be representative for this ECIR.

For any commercial facility, whatever method of mining is used, either surface or underground, the system must be capable of excavating large quantities of oil shale at a very low cost. The mine design must not only be cost effective, but also a strict concern must be directed toward health and safety and the effects on the physical, biological, human, and mining environments.[2]

References

1. U.S. Department of Energy/Assistant Secretary for Environment/Office of Technology Assessments, "An Assessment of Oil Shale Technologies," June 1980, pp. 123-128.

2. Cameron Engineers, Inc., Synthetic Fuels Data Handbook, 2nd ed., Denver, Colorado, 1978, pp. 51-53.

GLOSSARY

Blowdown	Water that is periodically removed from either the cooling towers or the coal-fired boiler to prevent concentration of total dissolved solids.
Capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.
Cooling tower drift loss	Aerosols of water that are lost in the atmosphere from the cooling towers.
Cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.
Direct mode	The carbonaceous residue on the retorted shale and the low-Btu retort gas are burned in the combustion zone to provide thermal energy for the retorting process.
Flue gas	Gases generated from the combustion of fossil fuel in the boiler.
Fugitive emissions	Unintentional emissions, such as blowing dust from a shale pile.
Indirect mode	Heat for retorting is supplied by hot retorting gases from an outside furnace, thereby eliminating combustion in the retort.
Leaching	The separation or dissolving of soluble minerals or metals out of an ore by percolation of water.
Net station heat rate	Amount of fuel input (in Btu) necessary to generate 1 kWh of electricity.
Raw shale	Oil shale that has not been retorted.
Recycle water	Water that is collected, treated, and reused at the facility.
Retort	A closed refractory chamber in which kerogen in the shale is thermally decomposed into crude shale oil.
Retort gas	Gas that is one of the products resulting from the retorting of oil shale, being high- or low-Btu quality depending on the process.

Retorted shale	Shale that has had the oil values extracted and still contains carbon.
Rubblize	The process of breaking up the oil shale deposits, usually with the help of explosives, into rough, angular, fragments.
Run-of-mine shale	Shale as it comes from the mine prior to sizing or other preparation.
Shale oil	Oil that is the dominant liquid product resulting from the retorting of oil shale; it is the liquid multicomponent hydrocarbon mixture resulting from the molecular rearrangement of kerogen in the oil shale.
Surface retorting	Extracting oil from the shale in an aboveground retort.
Syncrude	Shale oil that has been upgraded to remove nitrogen, sulfur, metals, and has little to no bottoms remaining.

ACRONYMS AND ABBREVIATIONS

A	cross sectional area (horizontal) of land affected by mining in acres
ANFO	ammonium nitrate fuel oil mixture (explosive)
°API	degrees on the American Petroleum Institute scale
BF	baghouse filter
CO	carbon monoxide
CO_2	carbon dioxide
ECIR	Environmental Characterization Information Report
HC	hydrocarbons
H_2S	hydrogen sulfide
NH_3	ammonia
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
SCF	standard cubic feet
SO_2	sulfur dioxide
sus	saybolt universal second
V	volume of raw shale storage pile
V_{SHALE}	volume of shale mined
W_{BLOW}	cooling tower blowdown water available for retorted shale disposal (= W_{SHALE})
$W_{BLOWDOWN}$	total amount of water available from cooling tower blowdown
$W_{CONDENSATE}$	water condensate available to meet process needs
$W_{DUST(CRUSHING)}$	amount of water needed to control dust from crushing and screening operations

$W_{DUST(MINE)}$	amount of water needed to control dust in the mine
W_{EVAP}	water requirement due to cooling tower evaporation
W_{MOIST}	amount of water added to retorted shale for cooling and dust control
W_{NET}	net makeup water requirement
$\bar{W}_{NET}$	net makeup water requirement per barrel of syncrude produced
$W_{PRODUCED}$	total amount of water produced during oil shale retorting process
$W_{PRODUCT\ GAS}$	amount of water produced during oil shale retorting process and contained in the product gas
$W_{PRODUCT\ OIL}$	amount of water produced during oil shale retorting process and contained in the product oil
$W_{RECYCLED}$	amount of water recycled to cooling tower from water treatment facility
W_{RUN}	runoff water from raw shale storage site
W_{RUNOFF}	runoff water from retorted shale disposal site
W_{SHALE}	cooling tower blowdown water available for retorted shale disposal (= W_{BLOW})
$W_{SHALE\ DISPOSAL}$	amount of water from the water treatment and recylcing facility for retorted shale disposal
$W_{SYNCRUDE}$	amount of water required for shale oil upgrading
W_{TOTAL}	total daily water requirement for retorted shale disposal
W_{TOW}	cooling tower makeup water
W_{TRF}	makeup water from Colorado River to water treatment facility
W_{SBS}	wet suppresion and baffled settling particulate control

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